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ASSESSMENT OF THE POTENTIAL OF CLEAN FUELS AND ENERGY TECHNOLOGY

BATTELLE COLUMBUS LABORATORIES

PREPARED FOR
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E. H. Hall, P. S. K. Choi, and E. L. Kropp

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A study was conducted to assess the potential of fuel cleaning, fuel conversion, and emission control technologies, in conjunction with the use of naturally occurring clean fuels, to reduce air emissions from fuel/energy processes sufficiently to maintain ambient air quality in the face of increasing fuel use between now and the year 2000. Total emissions and effluents produced by fuel-burning systems to the year 2000 were calculated according to three different scenarios reflecting different technology availability and fuel allocation. The impact of these emissions on ambient air quality was analysed. An overall index was developed for comparison of the potential usefulness of the energy technologies under consideration. Research and development priorities were recommended.

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By

Elton Hall
Paul Choi
Edward Kropp

Contract No. 68-01-2114
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Project Officer

James C. Johnson
Air Technology Branch
U.S. Environmental Protection Agency
Washington, DC 20460

Prepared for

OFFICE OF RESEARCH AND DEVELOPMENT
U.S. ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, DC 20460

ABSTRACT

The objectives of this study are: (1) to assess the potential of fuel cleaning, fuel conversion and emission control technologies, in conjunction with the use of naturally clean fuels, to reduce air emissions from fuel/energy processes sufficiently to maintain ambient air quality in the face of increasing fuel use between now and the year 2000, and (2) to recommend research and development priorities which will enhance the probability of successful fulfillment of the dual national goals of an adequate energy supply and clean air.

The assessment includes three phases: (1) calculation of total emissions and effluents produced by fuel-burning systems to the year 2000 according to three different scenarios, (2) analysis of the impact of emissions on ambient air quality, and (3) development of an overall index for comparison of the potential usefulness of the energy technologies under consideration.

The results show that energy technologies must be developed and implemented as rapidly as possible to maximize the use of domestic fuels, principally coal, and reduce our dependence on imported oil. Research and development priorities for various energy technologies were developed. The disproportionate impact of emissions from small sources on ambient air quality is demonstrated and recommendations pursuant to this problem are presented.

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CONCLUSIONS

The major results of this study may be summarized as follows.

(1) The basic fuel supply/demand forecasts of Dupree and West(1) were combined with a clean-fuel supply projection and a preliminary technology availability projection to develop a fuel utilization matrix. This matrix shows that there is expected to be a shortage of clean fuel and available energy technology resulting in the need to burn some dirty fuel without control in 1975 and 1980. The Dupree and West forecasts include large quantities of imported petroleum and gaseous fuels. Energy technologies must be developed and implemented as rapidly as possible to minimize this dependence on foreign fuel supply by maximizing the use of demestic fuel, princiaplly coal.

(2) The total emissions to be expected from the combustion of the projected quantities of fuel were calculated. The results show that, with the preliminary technology projection, about 29 million tons of SO_2 will be emitted in 1975, 18 million tons or 37 percent less in 1980, and 20 million tons in 2000. The reduction observed by 1980 and the moderate increase to the year 2000, in spite of a large increase in the fuel consumption projected during the period, are due to the assumed application of control technology. The effect of the applied technology in reducing emissions of SO_2 was estimated by repeating the calculation assuming no applied control technology. The observed reduction in SO_2 emissions was 4.5 million tons in 1975, 19 million tons in 1980, 29 million tons in 1985, and 46 million tons in 2000. The total NO_x emissions were shown to rise steadily throughout the period--18 million tons in 1975 to 27 million tons in 2000--reflecting the increase in fuel consumption and the lack of available NO_x control technology. The total particulate emissions are small--2.3 to 4.7 million tons from 1975 to 2000--compared with SO_2 and NO_x. This results from the assumption of 99 percent collection efficiency for particulates. The technology is available for achieving this efficiency but it is not universally practiced at this time. The estimates of particulate emissions do not include fine particulates.

(3) The potential impact of the total SO_2 emissions on ambient air quality was estimated by means of a model study of the Indianapolis Air Quality Control Region. The results indicate that, for Scenario 1 (allocation of clean fuel to small-source sectors), the maximum contribution to SO_2 concentrations from fuel combustion sources decreases from 1975 to 1980 because of the projected increase in the application of stack gas cleaning, then rises to slightly above the secondary standard by the year 2000 because of the projected increase in overall fuel use. For Scenario 3 (some dirty fuel burned in small-source sectors), the same trend occurs but the values are more than twice the Scenario 1 values in each year. This result reflects the disproportionate influence of small sources on ambient air quality. It should be noted that the result is merely an estimation of the impact to be expected for that AQCR given the projected growth in fuel consumption and available control technology.

(4) An assessment was made of the potential of energy technologies to contribute to the solution of the energy/environment problems. Each of ten technologies was evaluated with respect to six assessment criteria: residual emissions, availability, applicability, cost, energy efficiency, and probability of successful development. The final assessment yielded the following ranked order of technologies:

Highest rated group

- Stack gas cleaning, throwaway
- Physical coal cleaning
- Stack gas cleaning, by-product

Second group

- Residual oil desulfurization
- High-pressure fluidized-bed combustion of coal
- Chemically-active fluidized-bed combustion of oil

Third group

- Chemical coal cleaning

Fourth group

- Coal gasification, low Btu
- Coal refining (liquefaction)
- Coal gasification, high Btu

(5) Recommendations of technology research and development were made based on the needs identified in this study and the technology assessment performed.

RECOMMENDATIONS OF TECHNOLOGY RESEARCH PRIORITIES

The recommendations which follow were developed from the assessment of technologies which are in competition for the market for systems which are capable of utilizing coal or residual oil with minimum environmental impact. It should be noted that the assessment was based mainly on factors relating to overall characteristics of the technologies and detailed assessment of problems to be solved to perfect each technology was not made. The ratings are based in large part on what the technologies could contribute if the needed development is successful. Also they did not take into account other factors, e.g., processes for production of high Btu gas from coal are the only source of gas to supplement dwindling supply of domestic gas supplies which are essential for use in homes and commercial applications. Further, it does not consider that while optimistic assumptions relative to future availability suggest that most air pollutants can be kept under control without maximum development of all technologies, this can be achieved only if we have access to increasing supplies of imported oil and gas. The undesirability of heavy dependence on foreign fuel sources suggests that all technology with promise for utilizing coal with minimum environmental impact should be developed as rapidly as possible. Finally, it should be noted that advanced technologies such as fuel cells, use of solar energy and the like were not considered. Despite these limitations it is felt that the striking differences in the ranking suggest that certain activities are of outstanding importance from the standpoint of air pollution control. The following list defines priorities for further development of the technologies which have been assessed. The general recommendations are in order of priority. Specific projects which are suggested under each recommended area of R&D represent work felt to be of considerable importance but they cannot be taken to represent highest priority recommendations in that no comprehensive analysis of the relative merits of individual projects was made.

The significance of emissions from small sources is demonstrated in the body of the report by the calculations of predicted ambient air quality. This problem must be attacked in two ways:

    (1) Maximize the allocation of clean fuels to small sources. This solution is addressed in Recommendations 1, 2 and 8.
    (2) Accelerate the development of energy technologies applicable to small- and intermediate-size sources. This solution is addressed in Recommendations 3, 6, 7 and 8.

(1) Detailed analysis of current and projected clean fuels distribution and constraints on fuel switching flexibility to identify ways to maximize the allocation as clean fuels to small sources
    (a) Identify important misplaced blocks of clean fuel
    (b) Identify barriers to fuel switching such as long-term fuel supply contracts, outright ownership of fuels, availability of replacement fuels, and availability of clean fuel supply network.

(2) Stack gas cleaning for utilities and industrial sources of SO_x to maximize the use of domestic high sulfur fuel and free clean fuel for use in small sources
    (a) Engineering evaluation of sludge disposal methods (demonstration desirable)
    (b) Engineering evaluation of the reliability of the eleven lime/limestone systems on-stream or coming on-stream prior to July, 1974
    (c) Demonstrations on industrial sources

(3) Fluidized-bed combustion
    (a) Developmental studies on presently identified critical problems in fluidized combustion of coal, including solids handling, minimization of attrition and elutriation of bed materials, maximizing combustion efficiency and sorbent utilization, and cleaning of hot gases to minimize turbine damage in combined cycle application.

    (b) Demonstration of fluidized-bed combustion of high-sulfur residues. Coal cleaning and coal gasification/liquefaction processes result in combustible, high-sulfur residues which could be burned in a fluidized-bed combustor. A number of stack gas cleaning methods may be applied because of relatively high concentration of SO_2. This approach would reclaim the fuel value of the residues while eliminating the residue disposal problems.

    (c) Chemically-active fluidized bed - refinery demonstration. A refinery generates significant quantities of "dirty" fuel which could be burned on-site in a chemicall-active fluidized bed to provide needed energy to the refinery.

    (d) Chemically-active fluidized bed - lime kiln (once through) demonstration. Energy for lime kiln operation could be derived from residual oil burned in a chemically-active fluidized bed. The lime bed would not be recycled but would be simply included in the product mix.

(4) Control technology for NO_x. Adequate means for controlling emissions of NO_x are not available. This important area must be emphasized.

    (a) Development of coal firing techniques and combustion modifications to minimize NO_x emissions

    (b) Development of techniques for minimizing the conversion of fuel nitrogen

(5) Combined firing of prepared municipal refuse and pulverized coal. Although this approach was not considered in the current study, it has potential for providing an additional supply of energy with reduced emissions at relatively low cost while eliminating the solid waste disposal problem. The application of this practice should be accelerated as rapidly as possible.

    (a) Engineering study of means of adapting various types of existing boilers to combined firing

    (b) Supplement St. Louis study to develop optimum refuse preparation techniques

    (c) Studies of high-temperature corrosion by gases from refuse/coal firing

(6) Chemical cleaning of coal
    (a) Development of chemical processes capable of removing all or part of the organic sulfur contained in the coal
    (b) Development of chemical processes capable of removing all or part of the coal-bound nitrogen
(7) High Btu (pipeline) gas from coal
    (a) Development of systems for feeding coal into pressurized systems
    (b) Development of environmentally acceptable methods of char combustion (see fluidized-bed topics)
(8) Low Btu gas from coal
    (a) Demonstration of low Btu gasifiers on industrial plants now using low sulfur fuel. This application would free large amounts of natural gas and fuel oil for use in the residential/commercial sector.
    (b) Development of low Btu gas cleaning systems suitable for industrial applications

INTRODUCTION

The United States is faced with the need to satisfy a rapidly rising demand for energy. This demand must be met through the year 2000 by increased use of fossil fuels supplemented by the anticipated growth in electric power production by nuclear-fission generating facilities. Advanced energy sources such as solar energy conversion, nuclear fusion, geothermal, magnetohydrohynamics, and fuel cells are not expected to contribute a significant fraction of the total energy supply through the year 2000.

Consideration must be given also to the potential for added environmental damage inherent in the increased use of fossil fuels to satisfy our energy requirements. Methods to maximize the use of coal in environmentally sound ways must be developed to prevent excessive dependence on foreign sources of clean-burning, petroleum-based fuels. The United States Environmental Protection Agency, other government agencies, and certain industries have a number of research and development efforts in progress which are directed toward minimizing the pollutant emissions associated with the conversion of fossil fuels to useful energy. These efforts fall into three categories: fuel cleaning processes, fuel conversion processes, and emission control techniques. The objectives of this study are: (1) to assess the potential of these developmental technologies, in conjunction with the use of naturally clean fuels, to reduce air emissions from fuel/energy processes sufficiently to maintain ambient air quality in the face of increasing fuel use between now and the year 2000, and (2) to recommend research and development priorities which will enhance the probability of successful fulfillment of the dual national goals of an adequate energy supply and clean air.

The technologies specifically considered in this study are:

Fuel cleaning

(1) Physical coal cleaning
(2) Chemical coal cleaning
(3) Resid desulfurization

Fuel conversion

(4) Coal refining
(5) Coal gasification, low Btu
(6) Coal and oil gasification, high Btu

Emission control technologies

(7) Stack gas cleaning, throwaway
(8) Stack gas cleaning, by-product
(9) Fluidized-bed combustion of coal
(10) Chemically active fluidized-bed combutsion of oil.

These technologies, all directed toward the production of energy with reduced air emissions, are referred to collectively as energy technologies throughout this report.

The comparison of technologies from the standpoint of their contribution to improved air quality involved three steps. First, Department of Interior estimates of future usage for fossil fuels (coal, oil, and gas) by consuming sector (residential/commercial, industrial, utility) were analyzed to determine what emissions and effluents fuel burning systems would produce, with and without control technolgoies applied, to the year 2000. Three scenarios were considered in this step. In the first all available supplies of low-sulfur fuel were assumed to be burned in the domestic, commercial, and industrial sectors and available control technologies assumed to be applied to control of utilities. Estimates for the date of availability and extent of the applicability for the control technologies were based on expert opinion. For Scenario 2 mass emissions and total effluents which would result if no controls were applied were calculated for comparison purposes. In Scenario 3 the assumptions were identical to those of Scenario 1 except that part of the high-sulfur fuel which was assumed burned in utilities, because clean fuels and control systems were not available, was assumed to be burned in nonutility systems. Because the emission factors for all "dirty" fuel burning sources tend to be similar the total amounts of emissions and effluents calculated for Scenarios 1 and 3 were not significantly different.

The second step involved analysis of impacts on ambient air quality under conditions that would show the different impact which would result when a balance of "dirty" fuel, burned without control, was burned partly in small sources with short stacks as opposed to burning the entire balance in utility boilers with tall stacks. The source inventory for the Indianapolis air quality control region was used for this comparison. The population of processes included 11 utility boilers, 19 industrial boilers burning 12,500 to 50,000 tons of coal per year, 25 industrial boilers burning less than 12,500 tons of coal per year, 7 noncombustion sources of sulfur oxides, 165 other point sources and 207 area sources. Model studies were conducted to show the impact of each class of process on selected receptors. Conditions were chosen to permit a direct comparison of air quality impact with and without fuel distribution control which would make it possible to use all dirty fuel in utilities where it would do least harm.

The third step involved development of an overall index for comparison of the potential usefulness of the control technologies under consideration. Six criteria were used for a broad comparison of the technologies. They were (1) date of availability, (2) extent of the applicability, (3) the magnitude of uncontrollable residual emissions and effluents, (4) energy efficiency for the system, (5) cost to develop and apply the technology, and (6) probability of success in development of the new technologies. The ratings were based on expert opinion and were derived using methods intended to make them as objective as possible. They are not based on detailed investigations, e.g., probability of success ratings were based on the assumption that processes under development have come to their present stage by logical means involving rational judgments by the developers so that probability of success is mainly a function of how much additional development work is necessary. Judgments were made more on the amount of data believed available than on quality of the data and investigation of specific problems yet to be solved. The intent was to consider dominant characteristics for each technology and make quantitative comparisons of those most important to definition of R&D needs.

The fourth step involved development of R&D recommendations. These were based on the estimated importance of the technologies in control of environmental pollution from energy production without excessive dependence on foreign sources of fuel.

PROJECTED TOTAL EMISSIONS FROM FUEL COMBUSTION IN STATIONARY SOURCES

The calculation of total emissions from fuel combustion requires a projection of fuel use, a fuel allocation assumption, a set of energy technology availability projections, and unit emission factors for each combustion process. All of the calculations in this study employ the fuel-use projections contained in the energy supply/demand forecast of the Department of the Interior by Dupree and West.(1)* This energy forecast gives the projected consumption of energy resources by major sources and by consuming sectors for the years 1975, 1980, 1985, and 2000. The energy sources include: coal, petroleum, natural gas, nuclear power, and hydropower. The consuming sectors include: residential/commercial, industrial, transportation, electrical generation, and synthetic gas. For the purposes of this study the transportation sector was excluded since only stationary sources were considered. The inputs to the synthetic gas sector were combined with the inputs to the residential/commercial and industrial sectors, as indicated in the Dupree and West forecast. Finally, nonfuel uses of coal, petroleum, and natural gas were excluded. The total energy forecasts used in this study thus include the fossil-fuel inputs to the residential/commercial, industrial, and electrical sectors less the nonfuel uses as denoted by Dupree and West.

The total emissions resulting from the combustion of the quantities of fuels projected depend upon the nature of the fuel consumed, the manner in which the combustion takes place, and the degree of emission control applied. A portion of the projected fuel supply can be classified as clean fuel, i.e., fuel which can be burned without need for advanced emission control. Clean fuel supplies include natural gas, low sulfur coal, and low sulfur residual oil. The remainder of the fuel to be used is referred to as dirty fuel, i.e., that which requires the application of some energy technology if ambient air quality is to be maintained.

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*References are listed on page 98.

Total emissions were calculated for three different scenarios which incorporate variations in the allocation of clean fuels and in the energy technology applied. The quantities of coal, petroleum, and natural gas consumed in each sector and, therefore, the total quantities of each fuel are identical in each scenario. The assumptions, calculations, and results pertaining to each scenario are detailed in the following sections.

Scenario 1. Assumed Application of Energy Technologies, Preliminary Projection

Fuel Allocation Assumptions

The manner in which various fuels are allocated has a bearing on the total emissions in view of the fact that, in general, different emission factors are associated with different classes of combustion sources. An optimum fuel application strategy would assign clean fuels to smaller sources, which are unable to apply advanced emission control, and provide energy technologies for large sources. The fuel allocation for Scenario 1 was based on this premise. The supply of clean fuel was arbitrarily allocated to the residential/commercial sector first, to the industrial sector next, and any residual clean fuel was assigned to the electrical sector. It may be noted that the projected clean-fuel supply, presented in the following section, is sufficient to satisfy the residential/commercial and industrial sectors through the year 2000. Thus, in Scenario 1, dirty fuels were employed, with and without applied energy technology, only in the electrical sector. In this context, cleaned coal and high Btu gas from coal or oil were included in the clean fuel supply and both are allocated to the residential/commercial and industrial sectors.

Clean Fuel Supply Projection

The supply of clean fuel was estimated for 1975, 1980, 1985, and 2000 based on information available to date. The clean fuel supply projected in this section includes the naturally clean fuels such as natural gas, low sulfur coal, and products of normal refinery processes (distillate fuel oil and low sulfur resid) and cleaned fuels such as cleaned coal and desulfurized resid. Synthetic gas was also included since it can be substituted for natural gas and does not require on-site utilization. Only the quantities available for fuel uses in three sectors were projected: the residential and commercial sector, the industrial sector, and the utility sector.

Gaseous Fuel. A gaseous fuel supply was projected according to Dupree and West,(1) and the result is shown in Table 1. The domestic supply accounted for 96 percent of the total supply in 1971. The forecast, however, indicates that by 2000 the supply will rely considerably on imports (approximately 28 percent of the total supply). Synthesis of high Btu gas from coal and oil is projected to be developed and commercialized by 1980.

Petroleum. Among various petroleum products, distillate and residual fuel oils were allocated to fuel utilization in the three sectors under consideration. Lighter fractions such as gasoline and jet fuels would be used for transportation, and other fractions would be used for petrochemical feedstocks, asphalt, or other nonfuel purposes.

Distillate fuel oil is a clean fuel which contains less than one percent sulfur by weight. Minerals Yearbook 1973(3) indicated that distillate fuel oil accounted for 17.5 percent of the total consumption of petroleum product in 1971. In this projection, the ratio was assumed

TABLE 1. PROJECTION OF CLEAN GASEOUS FUEL SUPPLY[(a)] (Unit; 10^{12} Btu)

Fuel	Year 1975	1980	1985	2000
Domestic Natural Gas	22,600	23,000	22,500	22,900
Domestic Synthetic Gas		700	2,000	5,500
Total Domestic Supply	22,600	23,700	24,500	28,400
Pipeline Imports	2,100	3,100	4,200	7,600
LNG Imports	500	900	1,700	3,500
Total Imports	2,600	4,000	5,900	11,100
Total Supply	25,200	27,700	30,400	39,500
Nonfuel and Transportation Uses	1,700	2,200	2,400	3,500
Total Gaseous Fuel Supply	23,500	25,500	28,000	36,000

(a) Source: Reference 1

to hold for the forthcoming years to 2000. The distillate fuel oil supply was then estimated by using Dupree and West's(1) projection of total petroleum supply. The results are given in Table 2.

The low sulfur residual fuel oil (low sulfur resid) is defined as residual fuel oil containing less than 1 percent sulfur by weight. The limit of 1 percent sulfur content was restated as 0.5 percent for the 2000 projection because the projected increase in total fuel utilization will require a lower limit to maintain acceptable ambinet air quality. Such residual fuel oil is obtained either as a product of petroleum refining or by desulfurizing high sulfur residual fuel oil.

According to the study by Hittman Associates, Inc.,(4) the domestic supply of low sulfur residual fuel oil was 0.17 x 10^6 bbl/day in 1970 and the foreign supply was 0.9 x 10^6 bbl/day. The corresponding supplies of low sulfur residual fuel oil containing sulfur less than 0.5 percent were 0.04 x 10^6 bbl/day and 0.39 x 10^6 bbl/day for domestic and foreign sources, respectively. The foreign supply was mainly from South American refineries. An annual growth rate of 10 percent was estimated for the supply until 1980 and then the rate was assumed to decrease to 5 percent through 2000. Based on this information, the supply projection was made as shown in Table 2. The initial rapid increase in supply is attributed to the facts that the U. S. fuel demand for the industrial and electrical sectors will depend heavily on low sulfur resid until other fuel-cleaning or conversion technologies become commercialized; and that South American refineries are apparently willing to invest in, construct, and operate desulfurization plants. Such facilities are projected by Hittman to grow at the annual rate of 15 percent until 1980.

Coal. Low sulfur coal is defined as coal containing less than 1 percent sulfur by weight on dry basis. As in the case of residual oil, this definition was restated as 0.5 percent sulfur for the 2000 projection. Generally, the sulfur content of coal varies depending on the location of the coal basin and the type of coal. Hoffman, et. al.(5) conducted a survey of coal availability by sulfur content.

TABLE 2. PROJECTION OF CLEAN PETROLEUM FUEL SUPPLY

	Year			
	1975	1980	1985	2000
Distillate Fuel Oil,				
in 10^6 bbl	1,070	1,280	1,540	2,190
in 10^{12} Btu	6,200(a)	7,500	9,000	12,800
Low Sulfur Residual Fuel Oil ($\leq$ 1.0% S),				
in 10^6 bbl	630	1,010	1,290	
in 10^{12} Btu	3,800(b)	6,100	7,700	
Low Sulfur Residual Fuel Oil ($\leq$ 0.5% S),				
in 10^6 bbl				925
in 10^{12} Btu				5,500
Total Clean Petroleum Fuel Supply,				
in 10^{12} Btu	10,000	13,600	16,700	18,300

(a) Heating value of distillate fuel oil is 5,825,000 Btu/bbl.(2)

(b) Heating value of low sulfur residual fuel oil is 6,000,000 Btu/bbl.(2)

The domestic production of coal in 1971 by states is summarized in Minerals Yearbook 1971(3). To obtain the production of low-sulfur coal for the year, the coal production of each state was reclassified into several groups based on the sulfur content according to the information obtained by Hoffman, et al.(5) From this data the ratio of low sulfur coal to total coal production was obtained to be about 0.33 in terms of heating value. The corresponding ratio for low sulfur coal containing sulfur less than 0.5 percent was about 0.17. A low sulfur coal supply was projected according to Dupree and West's(1) projection of the total coal supply by assuming that the ratios hold for the forthcoming years. The results are shown in Table 3.

A supply projection for cleanable coal was made by a similar approach. However, in this projection, the supply of coal with sulfur contents ranging between 1 and 1.5 percent (or 0.5 and 0.75 percent for the year 2000) was estimated. Such coal would yield <1 percent sulfur (or <0.5 percent sulfur) if coal cleaning methods are assumed to remove about 35 percent of sulfur in coal, a nominal effectiveness for coal cleaning. Actual sulfur removal varies greatly with coal type and with the form of sulfur present.

Preliminary Energy Technology Availability Projection

In calculating the total emissions to be anticipated from the projected use of fuels, it is necessary to specify how the fuels are to be utilized. For this purpose a preliminary projection was made of the availability of the various energy technologies. This preliminary projection is shown in Table 4. The projected application of each technology is given in units of 10^{12} Btu. These units can be converted to equivalent electrical-generation capacity as follows: assuming a heat rate of 10^4 Btu/kwhr and a load factor of 68 percent, a 1000-MW power plant burns about 60×10^{12} Btu/yr or, conversely, 1000×10^{12} Btu/yr is equivalent to about 16,800 MW of electrical generation capacity. For some technologies the projections are based on published information. For others the projections

TABLE 3. PROJECTION OF CLEAN COAL FUEL SUPPLY (Unit; 10^{12}Btu)

Fuel	Year			
	1975	1980	1985	2000
Low Sulfur Coal (≤ 1% S, dry basis)	5,400	6,200	8,200	
Low Sulfur Coal (≤ 0.5% S, dry basis)				6,100
Cleanable Coal (≤ 1% S, dry basis)	1,800	2,100	2,800	
Cleanable Coal (≤ 0.5% S, dry basis)				2,900
Total Low Sulfur Coal	7,200	8,300	11,000	9,000

were obtained by estimating the year of first commercial availability, the capacity which might be available in the following reference year, and finally the growth rate which might be achieved during subsequent periods of time.

The application values entered in Table 4 for gasification of coal (high Btu) were taken directly from Dupree and West after converting their energy input values to outputs by the assumed conversion efficiency of 70 percent.

Projections of the availability of flue gas scrubbing technology vary widely from source to source. The Sulfur Oxide Control Technology Assessment Panel (SOCTAP),(6) the Mitre Corporation,(7) and EPA's Office of Planning and Evaluation (OP and E)(8) have made such projections which are summarized in the following tabulations:

	1975		1980	
Source	Cumulative Installed Capacity, MW	Approximate Equivalent in 10^{12}Btu	Cumulative Installed Capacity, MW	Approximate Equivalent in 10^{12}Btu
SOCTAP	10,000	600	161,000	9,700
Mitre Corp.	15,000	900	116,000	7,000
OP and E	25,000	1,500	45,000	2,700

The mean between the SOCTAP and the Mitre projections for 1975 and the Mitre value for 1980 (near the mean of the other two) were chosen for the projection in Table 4. The references cited above did not include projections beyond 1980. For this projection it was assumed that the growth rate would decline between 1980 and 1985 and that the total installed capacity would be less in the year 2000 than in 1985. The rationale for this assumed growth pattern is that, in the absence of sufficient alternative energy technology, flue-gas cleaning should grow as rapidly as possible through 1980; then the growth rate may be expected to reverse with the advent of fuel conversion and alternative combustion modes. This projection is optimistic in two respects. It assumes that improved technology will be developed and introduced very rapidly. Also, it assumes that large quantities of foreign oil will be available to meet clean fuel

TABLE 4. PRELIMINARY TECHNOLOGY AVAILABILITY PROJECTIONS

Technology	Year of 1st Comm-Size Plant	Year of Comm Availability	Projected Application, 10^{12} Btu			
			1975	1980	1985	2000
Coal Gasification, low Btu-Conv. Boiler	1978	1983	--	--	480	3900
Coal Gasification-High Btu	1977	1979	--	300(a)	1400(a)	5000(a)
Coal Liquefaction	1980	1984	--	--	300	2500
Fluidized-Bed Combustion of Coal	1977	1983	--	--	400	3000
Flue-Gas Cleaning	1968	1975	750	7000	9000	5500
Throwaway			610	5000	6230	2800
By-Product			140	2000	2760	2700
Chemically Active Fluidized-Bed (Oil)	1977	1979	--	200	1000	3000
Nuclear			2560(a)	6720(a)	11,750(a)	49,230(a)

(a) Dupree and West, Reference 1.

needs. If new coal-based technologies are not developed on the assumed schedule flue-gas cleaning could continue to grow until nuclear plants start to dominate in production of electrical energy. Further, even if new coal conversion technologies are developed at a very rapid rate their contribution will be small compared to projected deficits of domestic liquid fuels. Thus, the pressure to avoid over-dependence on foreign energy supplies could result in expansion of flue-gas cleaning beyond the estimated levels. The breakdown between the availability of throwaway and by-product processes for flue gas cleaning for 1975 is based on the approximate ratio (80/20) found to exist for those installations under construction or planned. For the later years the proportionate availability of by-product processes was assumed to increase, and the ratios, 70/30, 60/40, and 40/60, were chosen for 1980, 1985, and 2000, respectively.

Coal cleaning was not included in this projection. Quantities of coal cleanable to 1 percent sulfur or less were included in the clean fuels projection. Physical cleaning methods are available now for treating such quantities of coal. Similarly, desulfurized residual oil was included in the clean fuels projections.

Fuel Utilization Projections

The overall fuel use projected by Dupree and West(1) was combined with the fuel allocation and technology availability assumptions discussed previously to provide a matrix of projected fuel utilization. The results are presented in Tables 5, 6, and 7 for the residential/commercial, industrial, and electrical sectors, respectively. For each sector the fuel utilization is shown for type of fuel and energy technology applied (if any). The subtotals for each fuel type equal the projected fuel use for each sector as given by Dupree and West. The totals of clean fuels are equal to the totals projected in Tables 1, 2, and 3, and the extent of each applied energy technology is equal to that projected in Table 4. It should be noted that the supply of clean fuel is sufficient to meet the residential/commercial and industrial sector demand in each time period.

TABLE 5. FUEL UTILIZATION PROJECTION FOR RESIDENTIAL AND COMMERCIAL SECTOR[a]

Scenario 1

Fuel/Technology	Fuel Utilization Projection, 10^{12} Btu			
	1975	1980	1985	2000
Natural Gas (Clean Fuel)	8,660	9,480	10,060	10,800
Petroleum				
Distillate Fuel Oil (Clean Fuel)	5,750	6,440	7,480	9,520
Gasification, High Btu Gas	0	183	282	240
Subtotal	5,750	6,623	7,762	9,760
Coal				
Low Sulfur Coal (Clean Fuel)	325	300	100	0
Gasification, High Btu Gas	0	137	658	2,400
Subtotal	325	437	758	2,400
Total	14,735	16,540	18,580	22,960

(a) Excludes electricity purchased and non-fuel uses.

TABLE 6. FUEL UTILIZATION PROJECTION FOR INDUSTRIAL SECTOR(a)

Scenario 1

Fuel/Technology	Fuel Utilization Projection, 10^{12} Btu			
	1975	1980	1985	2000
Natural Gas (Clean Fuel)	11,040	11,750	12,440	17,040
Petroleum				
Distillate Fuel Oil (Clean Fuel)	450	1,060	1,520	3,280
Low Sulfur Resid (Clean Fuel) - Domestic	560	530	650	740
Low Sulfur Resid (Clean Fuel) - Imported	2,900	2,820	3,430	3,800
Gasification, High Btu Gas	0	217	318	260
Subtotal	3,910	4,627	5,918	8,080
Coal				
Low Sulfur Coal (Clean Fuel)	3,340	3,410	3,610	3,970
Cleanable Coal (Clean Fuel)	1,110	1,140	1,210	1,330
Gasification, High Btu Gas	0	163	742	2,600
Subtotal	4,450	4,713	5,562	7,900
Total	19,400	21,090	23,920	33,020

(a) Excludes electricity purchased and non-fuel uses.

TABLE 7. FUEL UTILIZATION PROJECTION FOR ELECTRICAL SECTOR

Scenario 1

Fuel/Technology	Fuel Utilization Projection, 10^{12} Btu			
	1975	1980	1985	2000
Natural Gas (Clean Fuel)	3,800	3,600	3,450	2,640
Petroleum				
Low Sulfur Resid (Clean Fuel) - Domestic	40	450	580	160
Low Sulfur Resid (Clean Fuel) - Imported	300	2,300	3,040	800
Chemically Active Fluidized Bed	0	200	1,000	3,080
High Sulfur Resid with Stack Gas Cleaning	50	350	2,030	1,000
High Sulfur Resid without Control	3,190	1,700	0	0
Subtotal	3,580	5,000	6,650	5,040
Coal				
Low Sulfur Coal (Clean Fuel)	1,735	2,490	4,490	2,130
Cleanable Coal (Clean Fuel)	690	960	1,590	1,570
Fluidized-Bed Combustion	0	0	400	3,000
Gasification, Low Btu Gas	0	0	480	3,820
Liquefaction	0	0	300	2,500
High Sulfur Coal with Stack Gas Cleaning				
Limestone Scrubber	560	4,650	4,200	1,800
MgO Scrubber	140	2,000	2,760	2,700
High Sulfur Coal without Control	5,775	560	0	0
Subtotal	8,900	10,660	14,220	17,520
Total	16,280	19,260	24,320	25,200

The combined clean fuel supply and energy technology is insufficient to meet the total energy demand in 1975, so that a quantity of dirty fuel is assumed to be burned without control in that year. Similarly, in 1980, a small deficit remains. However, with the assumed projections, the clean fuel supply plus the energy technology availability is sufficient to meet the demand for both 1985 and 2000 so that no dirty fuels are assumed to be consumed without control in those time periods.

Projected Total Emissions - Scenario 1

In calculating total emissions to be anticipated from the projected use of fuels for energy, the emissions arising from the entire fuel/energy cycle were included. Following the methodology of an earlier study carried out for the Office of Research and Development of EPA,(2) a modular approach was employed in which individual modules, consisting of extraction, transportation, conversion, or utilization phases of the fuel/energy cycle, were appropriately combined into systems characteristic of each mode of fuel utilization. The modules chosen for each system are listed in Table 8. Each fuel/technology combination included in the fuel utilization projections (Tables 5, 6, and 7) is included in Table 8 together with the corresponding chosen modules.

Some simplifying assumptions were made in order to keep the number of different systems to a manageable size. All residential/commercial sector fuels were assumed to be used for space heating. All industrial sector fuels were assumed to be used for on-site electrical generation or for steam raising. It was further assumed that the emission factors for fuels used to fire a steam raising boiler are equivalent to those associated with a steam-electric boiler. The principal exception to the fuel use assumption is the significant fraction of coal used in the industrial sector for the production of coke. There are a number of coal gasification processes under development. Only the Hygas process was included for high Btu gasification of coal and the Lurgi process was used for low Btu. Limestone scrubbing was selected for the throwaway type of stack-gas-cleaning technology and the MgO process was used to represent the by-product type.

TABLE 8. MODULES COMPRISING FUEL/TECHNOLOGY SYSTEMS

Scenario 1

Fuel/Technology System	Modules				
	Extraction	Transport	Processing/Conversion	Transport	Utilization
RESIDENTIAL AND COMMERCIAL SECTOR					
Natural Gas (Clean Fuel)	Gas Well	None	Desulfurization	Gas Pipeline	Space Heating
Petroleum					
Distillate Fuel Oil (Clean Fuel)	Oil Well	Oil Pipeline	U.S. Refinery	None	Space Heating
Gasification, High Btu Gas	Oil Well	Oil Pipeline	Gasification	Gas Pipeline	Space Heating
Coal					
Low Sulfur Coal (Clean Fuel)	Coal Mine	Rail	None	None	Space Heating
Gasification, High Btu Gas	Coal Mine	Rail	Hygas	Gas Pipeline	Space Heating
INDUSTRIAL SECTOR					
Natural Gas (Clean Fuel)	Gas Well	None	Desulfurization	Gas Pipeline	Conv. Boiler
Petroleum					
Distillate Fuel Oil (Clean Fuel)	Oil Well	Oil Pipeline	U.S. Refinery	None	Conv. Boiler
Low Sulfur Resid (Clean Fuel)	Oil Well	Oil Pipeline	U.S. Refinery	Barge	Conv. Boiler
Low Sulfur Resid (Clean Fuel)	Import	Import	Import	Tanker	Conv. Boiler
Gasification, High Btu Gas	Oil Well	Oil Pipeline	Gasification	Gas Pipeline	Conv. Boiler
Coal					
Low Sulfur Coal (Clean Fuel)	Coal Mine	Rail	None	None	Conv. Boiler
Cleanable Coal (Clean Fuel)	Coal Mine	None	Physical Cleaning	Rail	Conv. Boiler
Gasification, High Btu Gas	Coal Mine	Rail	Hygas	Gas Pipeline	Conv. Boiler
ELECTRICAL SECTOR					
Natural Gas (Clean Fuel)	Gas Well	None	Desulfurization	Gas Pipeline	Conv. Boiler
Petroleum					
Low Sulfur Resid (Clean Fuel)	Oil Well	Oil Pipeline	U.S. Refinery	Barge	Conv. Boiler
Low Sulfur Resid (Clean Fuel)	Import	Import	Import	Tanker	Conv. Boiler
Chem. Act. Fluidized Bed	Import	Import	Import	Tanker	Fluidized Bed Combustion
High Sulfur Resid with Stack Gas Cleaning	Import	Import	Import	Tanker	Conv. Boiler, Lime Scrub.
High Sulfur Resid without Control	Import	Import	Import	Tanker	Conv. Boiler
Coal					
Low Sulfur Coal (Clean Fuel)	Coal Mine	Rail	None	None	Conv. Boiler
Cleanable Coal (Clean Fuel)	Coal Mine	None	Physical Cleaning	Rail	Conv. Boiler
Fluidized Bed Combustion	Coal Mine	Rail	None	None	Fluidized Bed Combustion
Gasification, Low Btu Gas	Coal Mine	Rail	Lurgi Gas	None	Conv. Boiler
Liquefaction	Coal Mine	Rail	Liquefaction	None	Conv. Boiler
High Sulfur Coal with Stack Gas Cleaning	Coal Mine	Rail	None	None	Conv. Boiler, Lime Scrub.
High Sulfur Coal with Stack Gas Cleaning	Coal Mine	Rail	None	None	Conv. Boiler, MgO Scrub.
High Sulfur Coal without Control	Coal Mine	Rail	None	None	Conv. Boiler

The emissions associated with each module were quantified first on a unit basis, i.e., in pounds per million Btu. Emissions were identified for 10 pollutants as follows.

Air Emissions
- Nitrogen oxides, NO_x
- Sulfur dioxide, SO_2
- Carbon monoxide, CO
- Particulate, part
- Total organic material, TOMA

Water Emissions
- Suspended solids
- Dissolved solids
- Total organic material, TOMW

Solid Waste
- Ash
- Sludge

Some of the unit emissions data were taken from the previously cited earlier work(2) and the remainder were generated as required. A summary of these data as used in the calculations is given in Table 9. The unit emissions data are given in a more detailed format in Appendix A with footnotes detailing the derivation and the control technology assumptions involved in each case. Of note in the latter context are the following points:

(1) Stack gas cleaning modules assume 90 percent reduction in SO_2 and 20 percent reduction in NO_x

(2) Boiler modules assume 99 percent efficiency for particulate removal.

The total emissions for each fuel/technology system were obtained by summing the emissions of each pollutant from each module (Table 9) in the system to obtain the total pounds of each pollutant per million Btu input to the utilization module of the system. No weighting factors were used in this summation to reflect possible variations in the importance of emissions from one module to another. It was necessary, however, to include an efficiency correction in the calculation to properly account for the fact that, for example, more than a million Btu of coal must be produced in the coal mining module, with an attendant increase in pollutant emissions, to provide a million Btu input to a power plant, if an intermediate module

TABLE 9. UNIT EMISSIONS OF INDIVIDUAL MODULES

(Pounds Per Million Btu)

MODULES	EFF	UNIT EMISSIONS									
		NOX	SO2	CO	PART	TOMA(a)	SS(b)	DS(c)	TOMW(d)	ASH	SLUDGE
GAS WELL	.960	.2300	0.0000	0.0000	0.0000	.1000	0.0000	0.0000	0.0000	0.0000	0.0000
GAS DESULFURIZATION	1.000	0.0000	.0250	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
GAS PIPELINE	.959	.3040	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SPACE HEATING-NAT GAS	.730	.0810	.0010	.0150	.0050	.0043	0.0000	0.0000	0.0000	0.0000	0.0000
OIL WELL-ON-SHORE	1.010	0.0000	.0001	0.0000	0.0000	0.0000	0.0000	6.2000	.0080	0.0000	0.0000
OIL PIPELINE	.931	.3990	.0160	0.0000	.0070	.0303	0.0000	0.0000	0.0000	0.0000	0.0000
U.S. REFINERY-DOMESTIC	.920	.0230	.1200	.0030	.0020	.0250	.0040	.3900	.0310	0.0000	.0073
SPACE HEATING-DIST OIL	.730	.1350	.2630	.0300	.0170	.0040	0.0000	0.0000	0.0000	0.0000	0.0000
CRUDE OIL GASIFICATION	.770	.0990	.0430	0.0000	.0020	.0049	0.0000	.3200	0.0000	.0900	.0900
STRIP MINED COAL-WEST	.938	0.0000	0.0000	0.0000	.0760	0.0000	.2830	0.0000	0.0000	0.0000	0.0000
RAIL TRANSPORT-COAL	1.036	.2200	.0214	.0150	.0015	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SPACE HEATING-COAL(1% S)	.500	.1170	1.6730	3.4900	.7750	.7753	0.0000	0.0000	0.0000	6.9000	0.0000
HYGAS	.656	.2500	.5500	0.0000	.1200	.0014	0.0000	0.0000	0.0000	6.7000	25.8300
CONV BOILER-NAT GAS	.370	.1900	.0006	.0006	.0150	.0400	.0150	0.0000	0.0000	0.0000	0.0000
CONV BOILER-DIST OIL	.370	.7500	.3360	.0003	.0570	.0140	0.0000	0.0000	0.0000	0.0000	0.0000
OIL BARGE	.936	.0013	.0014	.0011	.0314	.0304	0.0000	0.0000	.0150	0.0000	0.0000
CONV BOILER-RESID(1% S)	.370	.7000	1.0400	0.0000	.0500	.0103	0.0000	0.0000	0.0000	0.0000	0.0000
OIL TANKER	.935	.0015	.0016	.0013	.0021	.0001	0.0000	0.0000	.0150	0.0000	0.0000
CONV BOILER-LOW S COAL	.370	.9800	1.6300	.0540	.0700	.0163	.0250	0.0000	.0110	9.0000	0.0000
PHYS CLEANING OF COAL	.830	.0060	.0040	0.0000	.0100	0.0000	0.0000	0.0000	0.0000	0.0000	.3700
FLUIDIZED BED COMB OF RESID	.390	.1600	.4500	0.0000	.0100	.0400	0.0000	0.0000	0.0000	3.0000	0.0000
CONV BOILER-LIME SCRUB(RESID)	.370	.7600	.3660	0.0000	.0005	.0103	0.0000	0.0000	0.0000	0.0000	13.8300
CONV BOILER-NO CONTROL(RESID)	.370	.7000	3.6600	0.0000	.0500	.0103	0.0000	0.0000	0.0000	0.0000	0.0000
FLUID BED COMB-COAL+COMB CYC	.330	.1400	.7000	0.0000	.0200	0.0000	0.0000	0.0000	0.0000	17.3000	0.0000
COAL GASIF(LURGI)+CONV BOILER	.259	.4000	.9300	0.0000	.0150	.1100	.0160	0.0000	.0020	9.8200	0.0000
CONV BOILER+PHYS CLEANED COAL	.370	.6400	1.4400	.0190	.0440	.0113	.0250	0.0000	.0110	5.4100	0.0000
COAL LIQUEFACTION(SOL REFIN)	.750	.2100	.0030	.0120	.2700	.0035	0.0000	0.0000	0.0000	16.0000	0.0000
CONV BOILER+SOL REFIN COAL	.370	.5600	.7100	.0370	.0004	.0103	.0250	0.0000	.0110	.0310	0.0000
CONV BOILER+LIME SCRUB(COAL)	.350	.6000	.5300	.0420	.1000	.0133	.0250	0.0000	.0110	2.4000	27.3900
CONV BOILER+MGO SCRUB(COAL)	.330	.6300	.5000	.0420	.1000	.0130	.0250	0.0000	.0110	2.4000	0.0000
CONV BOILER-NO CONTROL(COAL)	.370	.7500	4.7500	.0420	.1000	.0130	.0250	0.0000	.0110	12.0000	0.0000
STRIP MINED COAL(EAST)	.936	.0007	0.0000	0.0000	.1400	0.0000	.5500	.1900	0.0000	0.0000	.2400
COKE OVEN(0.95% S)	.900	.0017	.8030	.0530	.1460	.1750	0.0000	0.0000	0.0000	0.0000	0.0000
SPACE HEATING-RESID(3.5% S)	.700	.1350	3.0650	.0300	.0170	.0040	0.0000	0.0000	0.0000	0.0000	0.0000
SPACE HEATING-COAL(3% S)	.500	.1170	4.4100	3.4900	.7750	.7753	0.0000	0.0000	0.0000	6.9000	0.0000

(a) Total organic material - air.

(b) Suspended solids

(c) Dissolved solids

(d) Total organic material - water.

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(say physical coal cleaning) has an efficiency less than 100 percent. The module efficiency factors used in this calculation are also given in Table 9.

The total unit basis emissions for a given system were than multiplied by the fuel quantity projected for that system (Tables 5, 6, and 7) to obtain the total quantities of pollutants produced in the extraction, transportation, processing, and utilization of the projected quantity of fuel. The resulting total pollutant quantities were than summed over all of the systems in each sector, for each year, and finally for all sectors. A computer program was written to carry out the required calculations. The results of the calculations for Scenario 1 are compiled in Tables 10, 11, 12, and 13.

The results show that, with the preliminary technology availability projection, about 29 million tons of SO_2 will be produced in 1975 but that this would be reduced about 37 percent to 18 million tons by 1980, principally through the application of stack gas cleaning technology. In spite of the large increase in fuel consumption between 1980 and 2000, the SO_2 emissions would rise only moderately to 20 million tons due principally to the increased availability projected for fluidized bed combustion of coal and oil, low Btu gasification of coal and coal refining (liquefaction). It should be noted that if coal used for coking had been considered in the industrial sector, rather than assuming that all of the coal is burned in boilers, the total SO_2 emissions would be about one million tons per year less than is shown in Tables 11 and 13. This estimate is based on a projection of 2400 x 10^{12} Btu of coal used to make coke with 50 percent of the contained sulfur retained in the coke, and ultimately in the steel mill slag, and 50 percent emitted as SO_2 with the coke oven gases.

The total NO_x emissions rise steadily through the 1975-2000 period reflecting the increased fuel use and the lack of any significant NO_x control availability. The total particulate emissions are small compared with those of SO_2 because of the high particulate collection efficiency assumed for boilers. The technology for achieving such efficiency is currently available but it is not universally practiced. The stated particulate emissions do not specifically include fine particulates. Technology for fine particle control is not currently available.

TABLE 10. TOTAL EMISSIONS FOR SYSTEMS IN THE RESIDENTIAL/COMMERCIAL SECTOR, SCENARIO 1

SYSTEMS	EMISSIONS, THOUSANDS OF TONS									
	NOX	SO2	CO	PART	TOMA	SS	DS	TOMW	ASH	SLUDGE
					1975					
NATURAL GAS(CLEAN FUEL)	2705.53	117.21	64.95	21.65	468.83	0.00	0.00	0.00	0.00	0.00
DIST FUEL OIL(CLEAN FUEL)	483.00	1152.56	94.87	61.01	84.33	11.50	20244.17	29.66	0.00	20.12
GASIFICATION-OIL, HIGH BTU	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LOW S COAL(CLEAN FUEL)	22.26	239.10	569.56	137.56	125.94	45.50	0.00	0.00	1121.25	0.00
GASIFICATION-COAL, HIGH BTU	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL	3210.79	1508.87	729.39	220.22	679.10	57.00	20244.17	29.66	1121.25	20.12
					1980					
NATURAL GAS(CLEAN FUEL)	2961.71	128.31	71.10	23.70	513.22	0.00	0.00	0.00	0.00	0.00
DIST FUEL OIL(CLEAN FUEL)	540.96	1290.87	106.26	68.34	94.45	12.88	22673.48	32.10	0.00	22.54
GASIFICATION-OIL, HIGH BTU	43.98	5.90	1.37	.90	.79	0.00	777.14	1.00	7.63	7.63
LOW S COAL(CLEAN FUEL)	20.55	220.71	525.75	126.97	116.25	42.00	0.00	0.00	1035.00	0.00
GASIFICATION-COAL, HIGH BTU	46.42	39.51	2.65	24.23	.37	59.52	19.48	0.00	478.57	1868.83
TOTAL	3613.61	1685.29	707.13	244.13	725.09	114.40	23470.09	33.10	1521.20	1899.00
					1985					
NATURAL GAS(CLEAN FUEL)	3142.91	136.16	75.45	25.15	544.62	0.00	0.00	0.00	0.00	0.00
DIST FUEL OIL(CLEAN FUEL)	628.32	1499.33	123.42	79.37	109.71	14.96	26335.03	37.29	0.00	26.18
GASIFICATION-OIL, HIGH BTU	67.77	9.10	2.11	1.38	1.21	0.00	1197.56	1.54	11.76	11.76
LOW S COAL(CLEAN FUEL)	6.85	73.57	175.25	42.32	38.75	14.00	0.00	0.00	345.00	0.00
GASIFICATION-COAL, HIGH BTU	222.93	189.74	12.73	116.36	1.80	285.89	93.56	0.00	2298.54	8975.85
TOTAL	4068.78	1907.89	388.97	264.59	696.09	314.85	27626.15	38.83	2655.30	9013.79
					2000					
NATURAL GAS(CLEAN FUEL)	3374.10	146.17	81.00	27.00	584.69	0.00	0.00	0.00	0.00	0.00
DIST FUEL OIL(CLEAN FUEL)	799.68	1908.24	157.08	101.02	139.63	19.04	33517.31	47.46	0.00	33.32
GASIFICATION-OIL, HIGH BTU	57.67	7.74	1.80	1.18	1.03	0.00	1019.20	1.31	10.01	10.01
LOW S COAL(CLEAN FUEL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GASIFICATION-COAL, HIGH BTU	813.12	692.07	46.44	424.43	6.55	1042.75	341.26	0.00	8383.73	32738.65
TOTAL	5044.58	2754.22	286.32	553.62	731.89	1061.79	34877.77	48.77	8393.74	32781.98

TABLE 11. TOTAL EMISSIONS FOR SYSTEMS IN THE INDUSTRIAL SECTOR, SCENARIO 1

SYSTEMS	EMISSIONS, THOUSANDS OF TONS									
	NOX	SO2	CO	PART	TOMA	SS	DS	TOMW	ASH	SLUDGE
					1975					
NATURAL GAS(CLEAN FUEL)	5154.76	147.21	2.21	82.30	796.40	99.32	0.00	0.00	0.00	0.00
DIST FUEL OIL(CLEAN FUEL)	176.17	186.63	.74	13.77	8.45	.90	1584.33	2.24	0.00	1.57
LOW S RESID-DOMESTIC	205.64	330.36	1.15	15.69	19.15	1.12	1979.52	7.60	0.00	1.97
LOW S RESID-IMPORTED	1017.17	1510.32	1.88	75.54	14.64	0.00	0.00	21.75	0.00	0.00
GASIFICATION-OIL, HIGH BTU	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LOW S COAL(CLEAN FUEL)	1670.00	2757.84	115.23	236.30	26.72	509.35	0.00	19.37	15030.00	0.00
CLEANABLE COAL(CLEAN FUEL)	391.95	802.20	29.41	119.10	6.10	360.75	113.52	6.10	3002.55	317.86
GASIFICATION-COAL, HIGH BTU	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL	8615.71	5654.55	150.63	543.21	862.97	960.44	3677.37	55.47	19032.55	321.41
					1980					
NATURAL GAS(CLEAN FUEL)	5486.27	156.68	2.35	88.13	847.52	94.00	0.00	0.00	0.00	0.00
DIST FUEL OIL(CLEAN FUEL)	414.99	251.16	1.75	32.45	20.85	2.12	3731.97	[illegible]	0.00	3.71
LOW S RESID-DOMESTIC	194.62	312.66	1.09	14.85	9.60	1.05	1873.69	6.53	0.00	1.96
LOW S RESID-IMPORTED	989.11	1469.66	1.83	73.46	14.24	0.00	0.00	21.15	0.00	0.00
GASIFICATION-OIL, HIGH BTU	85.67	6.96	.04	2.15	4.94	1.74	921.52	1.19	9.05	9.05
LOW S COAL(CLEAN FUEL)	1705.00	2815.64	117.64	241.26	27.29	520.02	0.00	19.75	15345.00	0.00
CLEANABLE COAL(CLEAN FUEL)	402.55	823.88	30.21	122.32	6.27	370.50	116.59	6.27	3083.70	326.45
GASIFICATION-COAL, HIGH BTU	80.41	46.97	1.96	29.64	3.39	72.12	23.18	0.00	569.40	2223.50
TOTAL	9358.63	5882.60	156.88	604.25	934.07	1061.57	6656.74	59.27	19007.15	2564.59
					1985					
NATURAL GAS(CLEAN FUEL)	5808.44	165.88	2.49	93.30	897.39	99.52	0.00	0.00	0.00	0.00
DIST FUEL OIL(CLEAN FUEL)	595.08	360.16	2.51	46.53	29.89	3.04	5351.50	7.58	0.00	5.32
LOW S RESID-DOMESTIC	238.69	383.45	1.34	18.21	11.74	1.31	2297.66	8.13	0.00	2.29
LOW S RESID-IMPORTED	1703.07	1786.34	2.23	89.35	17.32	0.00	0.00	25.73	0.00	0.00
GASIFICATION-OIL, HIGH BTU	125.55	10.19	.06	3.15	7.09	2.54	1350.43	1.74	13.26	13.26
LOW S COAL(CLEAN FUEL)	1805.00	2980.78	124.54	255.41	28.88	550.52	0.00	19.85	16245.00	0.00
CLEANABLE COAL(CLEAN FUEL)	427.27	874.47	32.06	129.93	6.66	393.25	123.75	6.66	3273.05	346.50
GASIFICATION-COAL, HIGH BTU	366.03	213.82	8.94	134.93	15.34	328.32	105.51	0.00	2591.97	10121.70
TOTAL	10569.13	6775.08	174.18	770.70	1014.39	1378.50	9228.86	69.68	22123.28	10489.07
					2000					
NATURAL GAS(CLEAN FUEL)	7955.26	227.22	3.41	127.80	1229.23	136.32	0.00	0.00	0.00	0.00
DIST FUEL OIL(CLEAN FUEL)	1284.12	777.18	5.41	100.40	64.51	6.55	11547.98	16.35	0.00	11.49
LOW S RESID-DOMESTIC	271.74	436.54	1.52	20.73	13.41	1.49	2615.80	9.25	0.00	2.60
LOW S RESID-IMPORTED	1332.85	1979.04	2.47	98.99	19.19	0.00	0.00	29.50	0.00	0.00
GASIFICATION-OIL, HIGH BTU	102.65	8.33	.05	2.57	5.99	2.09	1104.13	1.42	10.84	10.94
LOW S COAL(CLEAN FUEL)	1985.09	3278.03	136.96	280.88	31.76	605.42	0.00	21.93	17865.00	0.00
CLEANABLE COAL(CLEAN FUEL)	469.64	961.19	35.24	142.70	7.31	432.25	135.02	7.31	3597.65	380.85
GASIFICATION-COAL, HIGH BTU	1282.58	749.22	31.33	472.80	53.90	1150.45	369.70	0.00	9082.38	35466.87

TABLE 12. TOTAL EMISSIONS FOR SYSTEMS IN THE ELECTRICAL SECTOR, SCENARIO 1

SYSTEMS	EMISSIONS, THOUSANDS OF TONS									
	NOX	SO2	CO	PART	TOMA	SS	DS	TOMW	ASH	SLUDGE
					1975					
NATURAL GAS(CLEAN FUEL)	1774.28	506.35	455.44	484.19	531.69	486.08	455.69	455.68	455.69	455.68
LOW S RESID-DOMESTIC	14.69	23.44	.28	1.29	.92	.29	141.60	.70	.20	.34
LOW S RESID-IMPORTED	105.22	156.24	.29	7.81	1.51	0.00	0.00	2.25	0.00	0.00
CHEM ACTIVE FLUIDIZED BED	0.00	0.00	0.00	0.00	0.33	0.00	0.00	0.00	0.00	0.00
HIGH S RESID-LIMESTONE SCRUB	17.54	9.19	.03	.86	.25	0.00	0.00	.39	0.00	345.90
HIGH S RESID-NO CONTROL	1118.89	5840.25	2.07	83.10	16.11	0.00	0.00	23.92	0.00	0.00
LOW S COAL(CLEAN FUEL)	867.50	1432.59	59.96	122.75	13.49	264.59	0.00	9.54	7807.59	0.00
CLEANABLE COAL(CLEAN FUEL)	243.65	498.66	18.29	74.03	3.90	224.25	73.57	3.90	1356.45	197.59
FLUIDIZED BED COMBUSTION-COAL	0.00	0.00	0.00	0.00	0.00	0.60	0.00	0.00	0.00	0.00
GASIFICATION-COAL, LOW BTU	0.00	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00
LIQUEFACTION-COAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HIGH S COAL-LIMESTONE SCRUB	173.66	140.39	15.96	67.62	3.64	161.00	50.40	3.08	672.00	7711.20
HIGH S COAL-MGO SCRUB	43.41	35.10	3.99	15.90	.91	48.25	12.60	.77	169.00	16.90
HIGH S COAL-NO CONTROL	2223.95	13719.67	164.59	697.33	37.54	1660.31	519.75	31.76	34659.00	693.00
TOTAL	6582.80	22361.89	721.71	1555.08	610.24	2836.76	1250.60	531.98	45619.93	9419.62
					1980					
NATURAL GAS(CLEAN FUEL)	1680.90	479.70	432.42	459.70	503.70	460.50	431.70	431.70	431.70	431.70
LOW S RESID-DOMESTIC	165.25	263.71	3.18	14.37	10.34	3.15	1592.95	7.89	2.76	1.96
LOW S RESID-IMPORTED	806.72	1197.84	1.49	59.91	11.61	0.00	0.00	17.25	0.00	0.00
CHEM ACTIVE FLUIDIZED BED	16.15	45.16	.13	1.21	4.31	0.00	0.00	1.50	300.00	0.00
HIGH S RESID-LIMESTONE SCRUB	122.76	64.33	.23	.46	1.77	0.00	0.00	2.63	0.00	2415.00
HIGH S RESID-NO CONTROL	596.27	3112.36	1.10	44.28	8.59	0.00	0.00	12.75	0.00	0.00
LOW S COAL(CLEAN FUEL)	1245.00	2055.99	85.90	176.17	19.92	379.72	0.00	13.69	11205.00	0.00
CLEANABLE COAL(CLEAN FUEL)	318.99	693.79	25.44	103.00	5.28	312.00	94.18	5.28	2595.80	274.91
FLUIDIZED BED COMBUSTION-COAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GASIFICATION-COAL, LOW BTU	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LIQUEFACTION-COAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HIGH S COAL-LIMESTONE SCRUB	1441.96	1165.75	132.52	551.49	30.23	1336.87	418.50	25.57	5580.00	64030.50
HIGH S COAL-MGO SCRUB	620.20	501.40	57.80	241.50	13.00	575.00	180.00	11.00	2439.00	240.00
HIGH S COAL-NO CONTROL	215.66	1330.39	15.96	67.62	3.54	161.00	50.40	3.08	1360.00	67.20
TOTAL	7249.87	10910.43	755.39	1729.71	612.08	3228.26	2771.73	532.34	25975.76	67463.15

TABLE 12. TOTAL EMISSIONS FOR SYSTEMS IN THE ELECTRICAL SECTOR, SCENARIO 1 (Continued)

SYSTEMS	EMISSIONS, THOUSANDS OF TONS									
	NOX	SO2	CO	PART	TOMA	SS	DS	TOMW	ASH	SLUDGE
						1985				
NATURAL GAS(CLEAN FUEL)	1610.86	459.72	414.40	439.59	482.71	441.31	413.71	413.71	413.71	413.71
LOW S RESID-DOMESTIC	212.99	339.89	4.10	18.52	13.32	4.08	2053.13	10.16	2.91	4.95
LOW S RESID-IMPORTED	1055.28	1583.23	1.98	79.19	15.35	0.00	0.00	22.50	0.00	0.00
CHEM ACTIVE FLUIDIZED BED	80.75	225.80	.65	6.05	20.05	0.00	0.00	7.50	1500.00	0.00
HIGH S RESID-LIMESTONE SCRUB	712.02	373.11	1.32	2.64	10.25	0.00	0.00	15.22	0.00	14007.00
HIGH S RESID-NO CONTROL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LOW S COAL(CLEAN FUEL)	2245.00	3707.39	154.90	317.67	35.92	684.72	0.00	24.69	20205.00	0.00
CLEANABLE COAL(CLEAN FUEL)	561.45	1149.09	42.13	170.60	8.75	516.75	162.61	8.75	4300.95	455.32
FLUIDIZED BED COMBUSTION-COAL	32.04	140.28	3.00	32.30	0.00	110.00	36.00	0.00	3450.00	48.00
GASIFICATION-COAL, LOW BTU	100.85	223.54	3.60	37.56	26.40	135.84	43.20	.48	2355.80	57.60
LIQUEFACTION-COAL	119.54	107.23	10.35	68.84	2.04	113.75	36.00	1.65	2404.65	48.00
HIGH S COAL-LIMESTONE SCRUB	1302.42	1052.94	119.70	597.15	27.30	1207.50	378.00	23.10	5040.00	57834.00
HIGH S COAL-MGO SCRUB	855.88	691.93	78.66	333.27	17.34	793.50	249.40	15.19	3312.00	331.20
HIGH S COAL-NO CONTROL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL	8900.07	10054.16	834.80	2013.38	660.03	4007.45	3371.06	543.25	42996.02	73199.78
						2000				
NATURAL GAS(CLEAN FUEL)	1232.66	351.78	317.11	336.38	369.38	337.70	316.58	316.58	316.58	316.58
LOW S RESID-DOMESTIC	58.75	93.76	1.13	5.11	3.58	1.12	565.38	2.90	.80	1.37
LOW S RESID-IMPORTED	280.60	416.64	.52	20.84	4.04	0.00	0.00	6.00	0.00	0.00
CHEM ACTIVE FLUIDIZED BED	248.71	695.46	2.00	18.63	61.75	0.00	0.00	23.10	4620.00	0.00
HIGH S RESID-LIMESTONE SCRUB	350.75	183.80	.65	1.30	5.05	0.00	0.00	7.50	0.00	6900.00
HIGH S RESID-NO CONTROL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LOW S COAL(CLEAN FUEL)	1065.00	1758.74	73.48	150.70	17.94	324.82	0.00	11.71	9585.00	0.00
CLEANABLE COAL(CLEAN FUEL)	554.39	1134.64	41.60	158.45	8.63	510.25	160.57	8.63	4245.85	449.59
FLUIDIZED BED COMBUSTION-COAL	240.30	1052.10	22.50	242.25	0.00	825.00	270.00	0.00	25950.00	360.00
GASIFICATION-COAL, LOW BTU	802.58	1778.97	28.65	298.91	210.10	1081.06	343.80	3.82	19755.20	458.40
LIQUEFACTION-COAL	996.17	893.58	86.25	573.71	17.00	947.92	300.00	13.75	20038.75	400.00
HIGH S COAL-LIMESTONE SCRUB	558.18	451.26	51.30	217.35	11.70	517.50	162.00	9.90	2160.00	24786.00
HIGH S COAL-MGO SCRUB	837.27	676.89	76.95	326.02	17.55	776.25	243.00	14.85	3240.00	324.00
HIGH S COAL-NO CONTROL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL	7225.36	9487.64	702.15	2359.66	725.92	5321.63	2362.33	418.65	88914.18	33995.94

TABLE 13. SUMMARY OF TOTAL EMISSIONS FOR EACH SECTOR AND TOTAL EMISSIONS FOR ALL SECTORS, SCENARIO 1

SECTORS	EMISSIONS, THOUSANDS OF TONS									
	NOX	SO2	CO	PART	TOMA	SS	OS	TOMW	ASH	SLUDGE
					1 9 7 5					
RESIDENTIAL AND COMMERCIAL	3210.79	1508.87	729.39	220.22	679.10	57.00	20244.17	28.66	1121.25	20.12
INDUSTRIAL	8615.71	5654.55	150.63	543.21	862.87	960.44	3677.37	55.47	18032.55	321.41
ELECTRICAL	6582.80	22361.89	721.71	1555.08	610.24	2836.76	1250.60	531.88	45619.83	9419.62
TOTAL	18409.29	29525.30	1601.73	2318.51	2152.21	3854.21	25172.15	616.02	64773.63	9761.15
					1 9 8 0					
RESIDENTIAL AND COMMERCIAL	3613.61	1685.29	707.13	244.13	725.09	114.40	23470.09	33.10	1521.23	1899.00
INDUSTRIAL	9358.63	5882.60	156.89	604.25	934.07	1061.57	6666.74	59.27	19007.15	2564.58
ELECTRICAL	7249.87	10910.43	755.39	1728.71	612.08	3228.26	2771.73	532.34	25875.76	67463.15
TOTAL	20222.11	18478.32	1619.41	2577.09	2271.24	4404.24	32908.56	624.72	46404.11	71926.73
					1 9 8 5					
RESIDENTIAL AND COMMERCIAL	4068.78	1907.89	388.97	264.59	696.09	314.85	27626.15	38.83	2655.30	9013.79
INDUSTRIAL	10569.13	6775.08	174.18	770.70	1014.39	1378.50	9228.86	69.68	22123.28	10489.07
ELECTRICAL	8900.07	10054.16	834.80	2013.38	660.03	4007.45	3371.06	543.25	42996.02	73199.78
TOTAL	23537.98	18737.13	1397.95	3048.67	2370.51	5700.81	40226.07	651.76	67774.61	92702.64
					2 0 0 0					
RESIDENTIAL AND COMMERCIAL	5044.58	2754.22	286.32	553.62	731.89	1061.79	34877.77	48.77	8393.74	32781.98
INDUSTRIAL	14684.84	8416.76	216.40	1246.88	1425.10	2334.57	15773.64	84.67	30555.87	35872.66
ELECTRICAL	7225.36	9487.64	702.15	2359.66	725.92	5321.63	2362.33	418.65	88914.18	33995.94
TOTAL	26954.78	20658.62	1204.87	4160.16	2882.92	8717.99	53013.74	552.10	127863.80	102650.57

Scenario 2. Assumed No Application of Energy Technology

To illustrate the degree of effectiveness of the various fuel conversion and emission control technologies incorporated in the Scenario 1 projections, a second series of calculations was performed in which no energy technology was applied. These calculations were carried out by substituting modules and systems without control for any system in Scenario 1 using either a fuel conversion or emission control technology. The fuel utilization matrix was unchanged. For example, the fuel utilization projection for the electrical sector called for 560 x 10^{12} Btu of coal to be burned with limestone scrubbing in 1975. For the Scenario 2 calculation, 560 x 10^{12}Btu of coal were assumed to be burned without control using the conventional boiler, 3 percent sulfur module and the resulting total emissions for 1975 entered for the coal/limestone scrubber system (now uncontrolled) in the computer printout. All other systems involving either fuel conversion or emissions control technology were treated similarly. Those systems which utilize clean fuel or cleaned fuel were unchanged in the Scenario 2 calculation.

Projected Total Emissions - Scenario 2

The projected total emissions for Scenario 2 are given for each system, each sector, and for all sectors in Tables 14, 15, 16, and 17. Comparison of the results of the calculations for Scenario 1 and Scenario 2 is provided in Table 18, which is a summary of the total emissions from all sectors for both scenarios. The energy technologies applied account for a 13 percent reduction in SO_2 emissions in 1975, as shown in Table 18. This factor increases to nearly 70 percent by the year 2000. The slight reduction in NO_x emissions shown in Scenario 1 as compared with Scenario 2 is due to the fact that somewhat reduced NO_x emissions are expected from stack gas cleaning and from fluidized bed combustion of coal and oil.

TABLE 14. TOTAL EMISSIONS FOR RESIDENTIAL/COMMERCIAL SECTOR, SCENARIO 2

SYSTEMS	NOX	SO2	CO	PART	TOMA	SS	DS	TOMW	ASH	SLUDGE
	EMISSIONS, THOUSANDS OF TONS									
					1975					
NATURAL GAS(CLEAN FUEL)	2705.53	117.21	64.95	21.65	468.83	0.00	0.00	0.00	0.00	0.00
DIST FUEL OIL(CLEAN FUEL)	483.00	1152.56	94.87	61.01	84.33	11.50	20244.17	28.66	0.00	20.12
GASIFICATION-OIL, HIGH BTU	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LOW S COAL(CLEAN FUEL)	22.26	239.10	569.56	137.56	125.94	45.50	0.00	0.00	1121.25	0.00
GASIFICATION-COAL, HIGH BTU	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL	3210.79	1508.87	729.39	220.22	679.10	57.00	20244.17	28.66	1121.25	20.12
					1980					
NATURAL GAS(CLEAN FUEL)	2961.71	128.31	71.10	23.70	513.22	0.00	0.00	0.00	0.00	0.00
DIST FUEL OIL(CLEAN FUEL)	540.96	1290.87	106.26	68.34	94.45	12.88	22673.48	32.10	0.00	22.54
GASIFICATION-OIL, HIGH BTU	15.37	36.68	3.02	1.94	2.68	.37	644.29	.91	0.00	.64
LOW S COAL(CLEAN FUEL)	20.55	220.71	525.75	126.97	116.25	42.00	0.00	0.00	1035.00	0.00
GASIFICATION-COAL, HIGH BTU	9.38	100.79	240.09	57.99	53.09	19.18	0.00	0.00	472.65	0.00
TOTAL	3547.98	1777.35	946.22	278.94	779.70	74.43	23317.77	33.01	1507.65	23.18
					1985					
NATURAL GAS(CLEAN FUEL)	3142.91	136.16	75.45	25.15	544.62	0.00	0.00	0.00	0.00	0.00
DIST FUEL OIL(CLEAN FUEL)	628.32	1499.33	123.42	79.37	109.71	14.96	26335.03	37.29	0.00	26.18
GASIFICATION-OIL, HIGH BTU	23.69	56.53	4.65	2.99	4.14	.56	992.84	1.41	0.00	.99
LOW S COAL(CLEAN FUEL)	6.85	73.57	175.25	42.32	38.75	14.00	0.00	0.00	345.00	0.00
GASIFICATION-COAL, HIGH BTU	45.07	484.09	1153.14	278.50	254.97	92.12	0.00	0.00	2270.10	0.00
TOTAL	3846.84	2249.67	1531.92	428.34	952.19	121.64	27327.88	38.69	2615.10	27.17
					2000					
NATURAL GAS(CLEAN FUEL)	3374.10	146.17	81.00	27.00	584.69	0.00	0.00	0.00	0.00	0.00
DIST FUEL OIL(CLEAN FUEL)	799.68	1908.24	157.08	101.02	139.63	19.04	33517.31	47.46	0.00	33.32
GASIFICATION-OIL, HIGH BTU	20.16	48.11	3.96	2.55	3.52	.48	844.97	1.20	0.00	.84
LOW S COAL(CLEAN FUEL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GASIFICATION-COAL, HIGH BTU	164.40	1765.68	4206.00	1015.80	930.00	336.00	0.00	0.00	8280.00	0.00
TOTAL	4358.34	3868.19	4448.04	1146.36	1657.83	355.52	34362.29	48.65	8280.00	34.16

TABLE 15. TOTAL EMISSIONS FOR INDUSTRIAL SECTOR, SCENARIO 2

SYSTEMS	EMISSIONS, THOUSANDS OF TONS									
	NOX	SO2	CO	PART	TOMA	SS	DS	TOMW	ASH	SLUDGE
					1975					
NATURAL GAS(CLEAN FUEL)	5154.76	147.21	2.21	82.80	796.40	88.32	0.00	0.00	0.00	0.00
DIST FUEL OIL(CLEAN FUEL)	176.17	106.63	.74	13.77	8.85	.90	1584.33	2.24	0.00	1.57
LOW S RESID-DOMESTIC	205.64	330.36	1.15	15.69	10.15	1.12	1979.52	7.00	0.00	1.97
LOW S RESID-IMPORTED	1017.17	1510.32	1.88	75.54	14.64	0.00	0.00	21.75	0.00	0.00
GASIFICATION-OIL, HIGH BTU	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LOW S COAL(CLEAN FUEL)	1670.00	2757.84	115.23	236.30	26.72	509.35	0.00	18.37	15030.00	0.00
CLEANABLE COAL(CLEAN FUEL)	427.46	2637.03	31.63	134.03	7.22	319.12	99.90	6.10	6660.00	133.20
GASIFICATION-COAL, HIGH BTU	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL	8651.21	7489.38	152.85	558.15	863.98	918.82	3663.75	55.47	21690.00	136.74
					1980					
NATURAL GAS(CLEAN FUEL)	5486.27	156.68	2.35	88.13	847.62	94.00	0.00	0.00	0.00	0.00
DIST FUEL OIL(CLEAN FUEL)	414.99	251.16	1.75	32.45	20.85	2.12	3731.97	5.28	0.00	3.71
LOW S RESID-DOMESTIC	194.62	312.66	1.09	14.85	9.60	1.06	1873.48	6.63	0.00	1.86
LOW S RESID-IMPORTED	989.11	1468.66	1.83	73.46	14.24	0.00	0.00	21.15	0.00	0.00
GASIFICATION-OIL, HIGH BTU	76.93	398.86	0.00	5.64	1.12	0.00	678.81	.88	0.00	0.00
LOW S COAL(CLEAN FUEL)	1705.00	2815.64	117.64	241.26	27.28	520.02	0.00	18.75	15345.00	0.00
CLEANABLE COAL(CLEAN FUEL)	439.01	2708.30	32.49	137.65	7.41	327.75	102.60	6.27	6840.00	136.80
GASIFICATION-COAL, HIGH BTU	62.77	387.24	4.65	19.68	1.06	46.86	14.67	.90	978.00	19.56
TOTAL	9368.71	8499.19	161.80	613.12	929.17	991.82	6401.53	59.86	23163.00	161.93
					1985					
NATURAL GAS(CLEAN FUEL)	5808.44	165.88	2.49	93.30	897.39	99.52	0.00	0.00	0.00	0.00
DIST FUEL OIL(CLEAN FUEL)	595.08	360.16	2.51	46.53	29.89	3.04	5351.50	7.58	0.00	5.32
LOW S RESID-DOMESTIC	238.69	383.45	1.34	18.21	11.78	1.31	2297.66	8.13	0.00	2.28
LOW S RESID-IMPORTED	1203.07	1786.34	2.23	89.35	17.32	0.00	0.00	25.73	0.00	0.00
GASIFICATION-OIL, HIGH BTU	112.73	584.50	0.00	8.27	1.64	0.00	994.75	1.28	0.00	0.00
LOW S COAL(CLEAN FUEL)	1805.00	2980.78	124.54	255.41	28.88	550.52	0.00	19.85	16245.00	0.00
CLEANABLE COAL(CLEAN FUEL)	465.97	2874.60	34.48	146.11	7.86	347.87	108.90	6.66	7260.00	145.20
GASIFICATION-COAL, HIGH BTU	285.74	1762.77	21.15	89.60	4.82	213.32	66.78	4.08	4452.00	89.04
TOTAL	10514.73	10898.47	188.74	746.77	999.59	1215.59	8819.60	73.30	27957.00	241.84
					2000					
NATURAL GAS(CLEAN FUEL)	7956.26	227.22	3.41	127.80	1229.23	136.32	0.00	0.00	0.00	0.00
DIST FUEL OIL(CLEAN FUEL)	1284.12	777.18	5.41	100.40	64.51	6.56	11547.98	16.35	0.00	11.48
LOW S RESID-DOMESTIC	271.74	436.54	1.52	20.73	13.41	1.49	2615.80	9.25	0.00	2.60
LOW S RESID-IMPORTED	1332.85	1979.04	2.47	98.99	19.19	0.00	0.00	28.50	0.00	0.00
GASIFICATION-OIL, HIGH BTU	92.17	477.89	0.00	6.76	1.34	0.00	813.32	1.05	0.00	0.00
LOW S COAL(CLEAN FUEL)	1985.00	3278.03	136.96	280.88	31.76	605.42	0.00	21.83	17865.00	0.00
CLEANABLE COAL(CLEAN FUEL)	512.18	3159.68	37.90	160.60	8.64	382.37	119.70	7.31	7980.00	159.60
GASIFICATION-COAL, HIGH BTU	1001.26	6176.82	74.10	313.95	16.90	747.50	234.00	14.30	15600.00	312.00
TOTAL	14435.58	16512.40	261.78	1110.11	1384.97	1879.67	15330.80	98.60	41445.00	485.68

TABLE 16. TOTAL EMISSIONS FOR ELECTRICAL SECTOR, SCENARIO 2

SYSTEMS	EMISSIONS, THOUSANDS OF TONS									
	NOX	SO2	CO	PART	TOMA	SS	DS	TOMW	ASH	SLUDGE
					1975					
NATURAL GAS(CLEAN FUEL)	1774.28	506.35	456.44	484.18	531.68	486.08	455.68	455.68	455.68	455.68
LOW S RESID-DOMESTIC	14.69	23.44	.28	1.28	.92	.28	141.60	.70	.20	.34
LOW S RESID-IMPORTED	105.22	156.24	.20	7.81	1.51	0.00	0.00	2.25	0.00	0.00
CHEM ACTIVE FLUIDIZED BED	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HIGH S RESID-LIMESTONE SCRUB	17.54	91.54	.03	1.30	.25	0.00	0.00	.38	0.00	0.00
HIGH S RESID-NO CONTROL	1118.89	5840.25	2.07	83.10	16.11	0.00	0.00	23.92	0.00	0.00
LOW S COAL(CLEAN FUEL)	867.50	1432.59	59.86	122.75	13.88	264.59	0.00	9.54	7807.50	0.00
CLEANABLE COAL(CLEAN FUEL)	265.72	1639.23	19.66	83.32	4.48	198.37	62.10	3.80	4140.00	82.80
FLUIDIZED BED COMBUSTION-COAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GASIFICATION-COAL, LOW BTU	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LIQUEFACTION-COAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HIGH S COAL-LIMESTONE SCRUB	215.66	1330.39	15.96	67.62	3.64	161.00	50.40	3.08	3360.00	67.20
HIGH S COAL-MGO SCRUB	53.91	332.60	3.99	16.90	.91	40.25	12.60	.77	840.00	16.80
HIGH S COAL-NO CONTROL	2223.95	13719.67	164.59	697.33	37.54	1660.31	519.75	31.76	34650.00	693.00
TOTAL	6657.37	25072.31	723.09	1565.60	610.93	2810.89	1242.13	531.88	51253.38	1315.82
					1980					
NATURAL GAS(CLEAN FUEL)	1680.90	479.70	432.42	458.70	503.70	460.50	431.70	431.70	431.70	431.70
LOW S RESID-DOMESTIC	165.25	263.71	3.18	14.37	10.34	3.16	1592.95	7.89	2.26	3.84
LOW S RESID-IMPORTED	806.72	1197.84	1.49	59.91	11.61	0.00	0.00	17.25	0.00	0.00
CHEM ACTIVE FLUIDIZED BED	70.15	366.16	.13	5.21	1.01	0.00	0.00	1.50	0.00	0.00
HIGH S RESID-LIMESTONE SCRUB	122.76	640.78	.23	9.12	1.77	0.00	0.00	2.63	0.00	0.00
HIGH S RESID-NO CONTROL	596.27	3112.36	1.10	44.28	8.58	0.00	0.00	12.75	0.00	0.00
LOW S COAL(CLEAN FUEL)	1245.00	2055.99	85.90	176.17	19.92	379.72	0.00	13.69	11205.00	0.00
CLEANABLE COAL(CLEAN FUEL)	369.70	2280.67	27.36	115.92	6.24	276.00	86.40	5.28	5760.00	115.20
FLUIDIZED BED COMBUSTION-COAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GASIFICATION-COAL, LOW BTU	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LIQUEFACTION-COAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HIGH S COAL-LIMESTONE SCRUB	1790.71	11047.00	132.52	561.49	30.23	1336.87	418.50	25.57	27900.00	558.00
HIGH S COAL-MGO SCRUB	770.20	4751.40	57.00	241.50	13.00	575.00	180.00	11.00	12000.00	240.00
HIGH S COAL-NO CONTROL	215.66	1330.39	15.96	67.62	3.64	161.00	50.40	3.08	3360.00	67.20
TOTAL	7833.33	27526.01	757.31	1754.29	610.04	3192.26	2759.95	532.34	60658.96	1415.96

TABLE 16. TOTAL EMISSIONS FOR ELECTRICAL SECTOR, SCENARIO 2 (Continued)

					1985					
NATURAL GAS(CLEAN FUEL)	1610.86	459.72	414.40	439.59	482.71	441.31	413.71	413.71	413.71	413.71
LOW S RESID-DOMESTIC	212.99	339.89	4.10	18.52	13.32	4.08	2053.13	10.16	2.91	4.95
LOW S RESID-IMPORTED	1066.28	1583.23	1.98	79.19	15.35	0.00	0.00	22.80	0.00	0.00
CHEM ACTIVE FLUIDIZED BED	350.75	1830.80	.65	26.05	5.05	0.00	0.00	7.50	0.00	0.00
HIGH S RESID-LIMESTONE SCRUB	712.02	3716.52	1.32	52.88	10.25	0.00	0.00	15.22	0.00	0.00
HIGH S RESID-NO CONTROL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LOW S COAL(CLEAN FUEL)	2245.00	3707.39	154.90	317.67	35.92	684.72	0.00	24.69	20205.00	0.00
CLEANABLE COAL(CLEAN FUEL)	612.31	3777.36	45.31	191.99	10.33	457.12	143.10	8.75	9540.00	190.80
FLUIDIZED BED COMBUSTION-COAL	154.04	950.28	11.40	48.30	2.60	115.00	36.00	2.20	2400.00	48.00
GASIFICATION-COAL, LOW BTU	184.85	1140.34	13.68	57.96	3.12	138.00	43.20	2.64	2880.00	57.60
LIQUEFACTION-COAL	115.53	712.71	8.55	36.22	1.95	86.25	27.00	1.65	1800.00	36.00
HIGH S COAL-LIMESTONE SCRUB	1617.42	9977.94	119.70	507.15	27.30	1207.50	378.00	23.10	25200.00	504.00
HIGH S COAL-MGO SCRUB	1062.88	6556.93	78.66	333.27	17.94	793.50	248.40	15.18	16560.00	331.20
HIGH S COAL-NO CONTROL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL	9944.92	34753.12	854.66	2108.79	625.85	3927.49	3342.55	547.61	79001.62	1586.26
					2000					
NATURAL GAS(CLEAN FUEL)	1232.66	351.78	317.11	334.38	369.38	337.70	316.58	316.58	316.58	316.58
LOW S RESID-DOMESTIC	58.75	93.76	1.13	5.11	3.68	1.12	566.38	2.80	.80	1.37
LOW S RESID-IMPORTED	280.60	416.64	.52	20.84	4.04	0.00	0.00	6.00	0.00	0.00
CHEM ACTIVE FLUIDIZED BED	1080.31	5638.86	2.00	80.23	15.55	0.00	0.00	23.10	0.00	0.00
HIGH S RESID-LIMESTONE SCRUB	350.75	1830.80	.65	26.05	5.05	0.00	0.00	7.50	0.00	0.00
HIGH S RESID-NO CONTROL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LOW S COAL(CLEAN FUEL)	1065.00	1758.74	73.48	150.70	17.04	324.82	0.00	11.71	9585.00	0.00
CLEANABLE COAL(CLEAN FUEL)	604.61	3729.05	44.74	189.58	10.20	451.37	141.30	8.63	9420.00	188.40
FLUIDIZED BED COMBUSTION-COAL	1155.30	7127.10	85.50	362.25	19.50	862.50	270.00	16.50	18000.00	360.00
GASIFICATION-COAL, LOW BTU	1471.08	9075.17	108.87	461.26	24.83	1098.25	343.80	21.01	22920.00	458.40
LIQUEFACTION-COAL	962.75	5939.25	71.25	301.87	16.25	718.75	225.00	13.75	15000.00	300.00
HIGH S COAL-LIMESTONE SCRUB	693.18	4276.26	51.30	217.35	11.70	517.50	162.00	9.90	10800.00	216.00
HIGH S COAL-MGO SCRUB	1039.77	6414.39	76.95	326.02	17.55	776.25	243.00	14.85	16200.00	324.00
HIGH S COAL-NO CONTROL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL	9994.76	46652.61	833.51	2477.65	514.77	5088.27	2268.06	452.34	102242.38	2164.75

TABLE 17. SUMMARY OF TOTAL EMISSIONS FOR EACH SECTOR AND TOTAL EMISSIONS FOR ALL SECTORS, SCENARIO 2

SECTORS	EMISSIONS, THOUSANDS OF TONS									
	NOX	SO2	CO	PART	TOHA	SS	DS	TOHW	ASH	SLUDGE
					1 9 7 5					
RESIDENTIAL AND COMMERCIAL	3210.79	1508.87	729.39	220.22	679.10	57.00	20244.17	28.66	1121.25	20.12
INDUSTRIAL	8651.21	7489.38	152.85	558.15	863.98	918.82	3663.75	55.47	21690.00	136.74
ELECTRICAL	6657.37	25072.31	723.09	1565.60	610.93	2810.89	1242.13	531.88	51253.38	1315.82
TOTAL	18519.37	34070.55	1605.33	2343.97	2154.01	3786.71	25150.05	616.02	74064.63	1472.69
					1 9 8 0					
RESIDENTIAL AND COMMERCIAL	3547.98	1777.35	946.22	278.94	779.70	74.43	23317.77	33.01	1507.65	23.18
INDUSTRIAL	9368.71	8499.19	161.80	613.12	929.17	991.82	6401.53	59.86	23163.00	161.93
ELECTRICAL	7833.33	27526.01	757.31	1754.29	610.04	3192.26	2759.95	532.34	60658.96	1415.94
TOTAL	20750.01	37802.55	1865.34	2646.35	2318.91	4258.51	32479.24	625.21	85329.61	1601.05
					1 9 8 5					
RESIDENTIAL AND COMMERCIAL	3846.84	2249.67	1531.92	428.34	952.19	121.64	27327.88	38.69	2615.10	27.17
INDUSTRIAL	10514.73	10898.47	188.74	746.77	999.59	1215.59	8819.60	73.30	27957.00	241.84
ELECTRICAL	9944.92	34753.12	854.66	2108.79	625.85	3927.49	3342.55	547.61	79001.62	1586.26
TOTAL	24306.50	47901.26	2575.32	3283.90	2577.64	5264.72	39490.02	659.61	109573.72	1855.27
					2 0 0 0					
RESIDENTIAL AND COMMERCIAL	4358.34	3868.19	4448.04	1146.36	1657.83	355.52	34362.29	48.65	8280.00	34.16
INDUSTRIAL	14435.58	16512.40	261.78	1110.11	1384.97	1879.67	15330.80	98.68	41445.00	485.68
ELECTRICAL	9994.76	46652.61	833.51	2477.65	514.77	5088.27	2268.06	452.34	102242.38	2164.75
TOTAL	28788.68	67033.21	5543.33	4734.13	3557.58	7323.46	51961.15	599.68	151967.38	2684.59

TABLE 18. COMPARISON OF TOTAL EMISSIONS FOR SCENARIO 1 AND SCENARIO 2

	Total Emissions, Thousands of Tons									
	NO_x	SO_2	CO	PART.	TOMA[(a)]	SS[(b)]	DS[(c)]	TOMW[(d)]	ASH	SLUDGE
						1975				
Scenario 1	18,409	29,525	1,601	2,318	2,152	3,854	25,172	616	64,773	9,761
Scenario 2	18,519	34,070	1,605	2,343	2,154	3,786	25,150	616	74,064	1,472
Difference, 2-1	110	4,545	4	25	2	-68	-22	0	9,291	-8,289
						1980				
Scenario 1	20,222	18,478	1,619	2,577	2,271	4,404	32,908	624	46,405	71,926
Scenario 2	20,750	37,802	1,865	2,646	2,318	4,258	32,479	625	85,329	1,601
Difference, 2-1	528	19,324	246	69	47	-146	-429	1	38,924	-70,325
						1985				
Scenario 1	23,537	18,737	1,397	3,048	2,370	5,700	40,226	651	67,774	92,702
Scenario 2	24,306	47,901	2,575	3,283	2,577	5,264	39,490	659	109,573	1,855
Difference, 2-1	769	29,164	1,178	235	207	-436	-736	8	41,799	-90,847
						2000				
Scenario 1	26,954	20,658	1,204	4,160	2,882	8,717	53,013	552	127,863	102,650
Scenario 2	28,788	67,033	5,543	4,734	3,557	7,323	51,961	599	151,967	2,684
Difference, 2-1	1,834	46,375	4,339	574	675	-1,394	-1,052	47	24,104	-99,966

(a) Total organic material - air
(b) Suspended solids
(c) Dissolved solids
(d) Total organic material - water

Scenario 3. Modified Fuel Allocation Assumption

Scenario 1 was based on the allocation of clean fuels to the smaller sources found within the residential/commercial and industrial sectors. Since some dirty fuel currently is consumed within these sectors, Scenario 3 was constructed in which a portion of the dirty fuel was assigned to the residential/commercial and industrial sectors in an attempt to reflect what would happen if long-term fuel supply contracts or other factors prevent the elimination of dirty fuels in small sources. Equivalent amounts of clean fuel were shifted to the electrical sector to maintain the correct subtotals.

Modified Fuel Utilization

The projection was made by modifying that for Scenario 1 in the following manner. Natural gas utilizations remained unchanged. Utilizations of high sulfur residual oil without control were newly projected by multiplying the total amount of high sulfur residual oil projected in Scenario 1 for 1975 by the fractions of the total residual oil currently consumed in each sector. These fractions were estimated to be 0.26, 0.2, and 0.54 for the residentail/commercial, industrial, and electrical sectors, respectively, for the year 1971 from data contained in Mineral Industry Surveys(9,10) and were assumed to hold for 1975. A constant continuing use of high sulfur residual oil in the residential/commercial and industrial sectors was assumed for the remaining periods because of the existence of long-term contracts or other constraints on fuel switching. The utilization of distillate fuel oil and low sulfur resid (imported) were adjusted to rebalance the petroleum fuel subtotals in the three sectors.

High sulfur coal utilizations in the residential/commercial and industrial sectors were based on data compiled by the Bureua of Mines. Tables giving shipments of bituminous coal and lignite by average suflur content by consumer use are presented for 1971 in Reference 3, and for 1971 in Reference 11. The data cover shipments by producers reporting sulfur content which included only 57 percent of the 1971 total production and 61 percent of the 1970 total production. On the basis of this incomplete data, 84 percent of the coal shipped to industrial and retail consumers in 1970 (excluding coke plants) was high sulfur coal, i.e., coal containing more than 1 percent sulfur. The corresponding figure for 1971 was 77 percent high sulfur coal. Data for coal shipments by sulfur content were not given in earlier editions of Minerals Yearbook. Since the data do not include the total U.S. production and are available for only 2 years, it is not possible to determine whether the indicated decrease in the percentage of high sulfur coal consumed in the residential/commercial and industrial sectors (84 percent in 1970 versus 77 percent in 1971) reflects a continuing trend. For this reason the approximate ratio, 75 percent high sulfur coal and 25 percent low sulfur coal was chosen and this ratio was assumed to be constant for each time period. Thus, the coal use projections for Scenario 3 were obtained by shifting 75 percent of the Scenario 1 low sulfur coal quantities in the residential/commercial and industrial sectors to high sulfur coal. The projections for low sulfur and high sulfur coal utilizations in the electrical sector were adjusted to rebalance the coal subtotals.

The resulting fuel utilization projections for Scenario 3 are given in Tables 19, 20, and 21. It is clear that these projections are only approximate with respect to the distribution of high sulfur fuel among the consuming sectors. A more definitive analysis would require a detailed examination of the current end use of such fuels and the factors limiting the flexibility for fuel switching. Such analysis is beyond the scope of this study, however, the subject is of such importance that it warrants further study.

Projected Total Emissions - Scenario 3

The modifications to the fuel utilization projections required the addition of systems not used in Scenario 1. The revised list of modules used in the Scenario 3 systems is given in Table 22.

TABLE 19. FUEL UTILIZATION PROJECTION FOR RESIDENTIAL AND COMMERCIAL SECTOR[(a)]

Scenario 3

Fuel/Technology	Fuel Utilization Projection, 10^{12} Btu			
	1975	1980	1985	2000
Natural Gas (Clean Fuel)	8,660	9,480	10,060	10,800
Petroleum				
Distillate Fuel Oil (Clean Fuel)	4,914	5,640	6,680	8,720
Gasification, High Btu Gas	0	183	282	240
High Sulfur Resid Without Control	836	800	800	800
Subtotal	5,750	6,623	7,762	9,760
Coal				
Low Sulfur Coal (Clean Fuel)	80	75	25	0
Gasification, High Btu Gas	0	137	658	2,400
High Sulfur Coal Without Control	245	225	75	0
Subtotal	325	437	758	2,400
Total	14,735	16,540	18,580	22,960

(a) Excludes electricity purchased and non-fuel uses.

TABLE 20. FUEL UTILIZATION PROJECTION FOR INDUSTRIAL SECTOR[a]

Scenario 3

Fuel/Technology	Fuel Utilization Projection, 10^{12} Btu			
	1975	1980	1985	2000
Natural Gas (Clean Fuel)	11,040	11,750	12,440	17,040
Petroleum				
Distillate Fuel Oil (Clean Fuel)	1,286	1,860	2,320	4,080
Low Sulfur Resid (Clean Fuel) - Domestic	560	530	650	740
Low Sulfur Resid (Clean Fuel) - Imported	1,423	1,420	2,030	2,400
Gasification, High Btu Gas	0	217	318	260
High Sulfur Resid without Control	641	600	600	600
Subtotal	3,910	4,627	5,918	8,080
Coal				
Low Sulfur Coal (Clean Fuel)	835	853	903	993
Cleanable Coal (Clean Fuel)	1,110	1,140	1,210	1,330
Gasification, High Btu Gas	0	163	742	2,600
High Sulfur Coal Without Control	2,505	2,557	2,707	2,977
Subtotal	4,450	4,713	5,562	7,900
Total	19,400	21,090	23,920	33,020

(a) Excludes electricity purchased and non-fuel uses.

TABLE 21. FUEL UTILIZATION PROJECTION FOR ELECTRICAL SECTOR

Scenario 3

Fuel/Technology	Fuel Utilization Projection, 10^{12} Btu			
	1975	1980	1985	2000
Natural Gas (Clean Fuel)	3,800	3,600	3,450	2,640
Petroleum				
Low Sulfur Resid (Clean Fuel) - Domestic	40	450	580	160
Low Sulfur Resid (Clean Fuel) - Imported	1,777	3,700	4,440	2,200
Chemically Active Fluidized Bed	0	200	1,000	2,180
High Sulfur Resid with Stack Gas Cleaning	50	350	630	500
High Sulfur Resid without Control	1,713	300	0	0
Subtotal	3,580	5,000	6,650	5,040
Coal				
Low Sulfur Coal (Clean Fuel)	4,485	5,272	7,272	5,107
Cleanable Coal (Clean Fuel)	690	960	1,590	1,570
Fluidized-Bed Combustion	0	0	400	3,000
Gasification, Low Btu Gas	0	0	480	3,820
Liquefaction	0	0	300	2,500
High Sulfur Coal with Stack Gas Cleaning				
Limestone Scrubber	560	3,115	2,700	600
MgO Scrubber	140	1,313	1,478	923
High Sulfur Coal without Control	3,025	0	0	0
Subtotal	8,900	10,660	14,220	17,520
Total	16,280	19,260	24,320	25,200

TABLE 22. MODULES COMPRISING FUEL/TECHNOLOGY SYSTEMS

Scenario 3

Fuel/Technology System	Modules				
	Extraction	Transport	Processing/Conversion	Transport	Utilization
RESIDENTIAL AND COMMERCIAL SECTOR					
Natural Gas (Clean Fuel)	Gas Well	None	Desulfurization	Gas Pipeline	Space Heating
Petroleum					
Distillate Fuel Oil (Clean Fuel)	Oil Well	Oil Pipeline	U.S. Refinery	None	Space Heating
Gasification, High Btu Gas	Oil Well	Oil Pipeline	Gasification	Gas Pipeline	Space Heating
High Sulfur Resid without Control	Import	Import	Import	Tanker	Space Heating
Coal					
Low Sulfur Coal (Clean Fuel)	Coal Mine	Rail	None	None	Space Heating
Gasification, High Btu Gas	Coal Mine	Rail	Hygas	Gas Pipeline	Space Heating
High Sulfur Coal without Control	Coal Mine	Rail	None	None	Space Heating
INDUSTRIAL SECTOR					
Natural Gas (Clean Fuel)	Gas Well	None	Desulfurization	Gas Pipeline	Conv. Boiler
Petroleum					
Distillate Fuel Oil (Clean Fuel)	Oil Well	Oil Pipeline	U.S. Refinery	None	Conv. Boiler
Low Sulfur Resid (Clean Fuel)	Oil Well	Oil Pipeline	U.S. Refinery	Barge	Conv. Boiler
Low Sulfur Resid (Clean Fuel)	Import	Import	Import	Tanker	Conv. Boiler
Gasification, High Btu Gas	Oil Well	Oil Pipeline	Gasification	Gas Pipeline	Conv. Boiler
High Sulfur Resid without Control	Import	Import	Import	Tanker	Conv. Boiler
Coal					
Low Sulfur Coal (Clean Fuel)	Coal Mine	Rail	None	None	Conv. Boiler
Cleanable Coal (Clean Fuel)	Coal Mine	None	Physical Cleaning	Rail	Conv. Boiler
Gasification, High Btu Gas	Coal Mine	Rail	Hygas	Gas Pipeline	Conv. Boiler
High Sulfur Coal without Control	Coal Mine	Rail	None	None	Conv. Boiler
ELECTRICAL SECTOR					
Natural Gas (Clean Fuel)	Gas Well	None	Desulfurization	Gas Pipeline	Conv. Boiler
Petroleum					
Low Sulfur Resid (Clean Fuel)	Oil Well	Oil Pipeline	U.S. Refinery	Barge	Conv. Boiler
Low Sulfur Resid (Clean Fuel)	Import	Import	Import	Tanker	Conv. Boiler
Chem. Act. Fluidized Bed	Import	Import	Import	Tanker	Fluidized Bed Combustion
High Sulfur Resid with Stack Gas Cleaning	Import	Import	Import	Tanker	Conv. Boiler, Lime Scrub.
High Sulfur Resid without Control	Import	Import	Import	Tanker	Conv. Boiler
Coal					
Low Sulfur Coal (Clean Fuel)	Coal Mine	Rail	None	None	Conv. Boiler
Cleanable Coal (Clean Fuel)	Coal Mine	None	Physical Cleaning	Rail	Conv. Boiler
Fluidized Bed Combustion	Coal Mine	Rail	None	None	Fluidized Bed Combustion
Gasification, Low Btu Gas	Coal Mine	Rail	Lurgi Gas	None	Conv. Boiler
Liquefaction	Coal Mine	Rail	Liquefaction	None	Conv. Boiler
High Sulfur Coal with Stack Gas Cleaning	Coal Mine	Rail	None	None	Conv. Boiler, Lime Scrub.
High Sulfur Coal with Stack Gas Cleaning	Coal Mine	Rail	None	None	Conv. Boiler, MgO Scrub.
High Sulfur Coal without Control	Coal Mine	Rail	None	None	Conv. Boiler

Total emissions were calculated by the same procedure used for Scenario 1 using the unit-basis module emission data from Table 9, the modified fuel utilization projections of Tables 19, 20, 21, and the module/systems as defined in Table 22. The results of the calculations are presented in Tables 23, 24, 25, and 26.

Comparison of the results for Scenario 1 and Scenario 3 is provided in Table 27, which is a summary of the total emissions for both scenarios.

The results for 1975 show that shifting dirty fuels from sector to sector does not affect the total emissions significantly as the emission factors for the modules involved are similar. The increase in total SO_2 emissions from Scenario 1 to Scenario 3 in 1980, 1985, and 2000 is the result of substituting low sulfur coal for some stack gas cleaning capacity. This was necessary to maintain the balance of total coal burned and the ratio of high sulfur coal to low sulfur coal. These increases for the utility sector have little effect on calculated air quality in Scenario 3 as is demonstrated in Appendix B.

It should be noted that, although the allocation of some dirty fuel to the residential/commercial and industrial sectors in Scenario 3 did not result in a large change in total emissions as compated with Scenario 1, in which only clean fuels were allocated to those sectors, this is not to say that the impact on ambient air quality would be similar for both scenarios. This question is addressed in the following section.

TABLE 23. TOTAL EMISSIONS FOR SYSTEMS IN THE RESIDENTIAL/COMMERCIAL SECTOR, SCENARIO 3

SYSTEMS	EMISSIONS, THOUSANDS OF TONS									
	NOX	SO2	CO	PART	TOMA	SS	DS	TOMW	ASH	SLUDGE
					1975					
NATURAL GAS(CLEAN FUEL)	2705.53	117.21	64.95	21.65	468.93	0.00	0.00	0.00	0.00	0.00
DIST FUEL OIL(CLEAN FUEL)	412.74	984.99	81.08	52.14	72.37	9.83	17300.85	24.50	0.00	17.20
GASIFICATION-OIL, HIGH BTU	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HIGH S RESID-NO CONTROL	57.06	1283.09	13.08	7.98	1.71	0.00	0.00	6.27	0.00	0.00
LOW S COAL(CLEAN FUEL)	5.48	58.86	140.20	33.86	31.00	11.20	0.00	0.00	276.00	0.00
GASIFICATION-COAL, HIGH BTU	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HIGH S COAL-NO CONTROL	15.81	540.40	429.36	112.27	94.94	67.37	22.05	0.00	845.25	29.40
TOTAL	3197.65	2984.54	728.69	227.91	668.56	88.40	17322.90	30.77	1121.25	46.60
					1980					
NATURAL GAS(CLEAN FUEL)	2961.71	128.31	71.10	23.70	513.22	0.00	0.00	0.00	0.00	0.00
DIST FUEL OIL(CLEAN FUEL)	473.76	1130.51	93.06	59.85	82.72	11.28	19856.89	28.11	0.00	19.74
GASIFICATION-OIL, HIGH BTU	43.98	5.90	1.37	.90	.78	0.00	777.14	1.00	7.63	7.63
HIGH S RESID-NO CONTROL	54.60	1227.84	12.52	7.64	1.64	0.00	0.00	6.00	0.00	0.00
LOW S COAL(CLEAN FUEL)	5.14	55.18	131.44	31.74	29.05	10.50	0.00	0.00	258.75	0.00
GASIFICATION-COAL, HIGH BTU	46.42	39.51	2.65	24.23	.37	59.52	19.49	0.00	478.57	1868.83
HIGH S COAL-NO CONTROL	15.43	496.28	394.31	103.11	87.19	61.88	20.25	0.00	776.25	27.00
TOTAL	3601.03	3083.52	706.45	251.16	714.99	143.19	20673.76	35.11	1521.20	1923.20
					1985					
NATURAL GAS(CLEAN FUEL)	3142.91	136.16	75.45	25.15	544.52	0.00	0.00	0.00	0.00	0.00
DIST FUEL OIL(CLEAN FUEL)	561.12	1338.97	110.22	70.88	97.97	13.36	23518.45	33.30	0.00	23.39
GASIFICATION-OIL, HIGH BTU	67.77	9.10	2.11	1.38	1.21	0.00	1197.56	1.54	11.76	11.76
HIGH S RESID-NO CONTROL	54.60	1227.84	12.52	7.64	1.64	0.00	0.00	6.00	0.00	0.00
LOW S COAL(CLEAN FUEL)	1.71	18.39	43.81	10.58	9.69	3.50	0.00	0.00	86.25	0.00
GASIFICATION-COAL, HIGH BTU	222.93	189.74	12.73	116.36	1.90	285.89	93.56	0.00	2298.54	8975.85
HIGH S COAL-NO CONTROL	5.14	165.43	131.44	34.37	29.05	20.63	6.75	0.00	258.75	9.00
TOTAL	4056.19	3085.63	388.29	266.37	685.99	323.37	24816.32	40.84	2655.30	9019.99
					2000					
NATURAL GAS(CLEAN FUEL)	3374.10	146.17	81.00	27.00	584.63	0.00	0.00	0.00	0.00	0.00
DIST FUEL OIL(CLEAN FUEL)	732.48	1747.88	143.88	92.53	127.89	17.44	30700.73	43.47	0.00	33.52
GASIFICATION-OIL, HIGH BTU	57.67	7.74	1.80	1.18	1.03	0.00	1019.20	1.31	10.01	10.01
HIGH S RESID-NO CONTROL	54.60	1227.84	12.52	7.64	1.64	0.00	0.00	6.00	0.00	0.00
LOW S COAL(CLEAN FUEL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GASIFICATION-COAL, HIGH BTU	813.12	692.07	46.44	424.43	6.55	1042.75	341.26	0.00	8383.73	32735.65
HIGH S COAL-NO CONTROL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL	5031.98	3821.70	285.64	552.77	721.80	1060.19	32[illegible]1.19	50.78	8393.74	32779.18

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TABLE 24. TOTAL EMISSIONS FOR SYSTEMS IN THE INDUSTRIAL SECTOR, SCENARIO 3

SYSTEMS	EMISSIONS, THOUSANDS OF TONS									
	NOX	SO2	CO	PART	TOMA	SS	DS	TOMW	ASH	SLUDGE
					1975					
NATURAL GAS(CLEAN FUEL)	5154.75	147.21	2.21	82.80	796.40	88.32	0.00	0.00	0.00	0.00
DIST FUEL OIL(CLEAN FUEL)	533.47	304.71	2.12	39.37	25.29	2.57	4527.65	6.41	0.00	4.50
LOW S RESID-DOMESTIC	205.64	330.36	1.15	15.69	10.15	1.12	1979.52	7.00	0.00	1.97
LOW S RESID-IMPORTED	499.12	741.10	.92	37.07	7.19	0.00	0.00	10.67	0.00	0.00
GASIFICATION-OIL, HIGH BTU	0.00	0.00	0.00	0.00	0.10	0.00	0.00	0.00	0.00	0.00
HIGH S RESID-NO CONTROL	224.83	1173.54	.42	16.70	3.24	0.00	0.00	4.81	0.00	0.00
LOW S COAL(CLEAN FUEL)	417.50	689.45	28.81	59.08	6.59	127.34	0.00	4.59	3757.50	0.00
CLEANABLE COAL(CLEAN FUEL)	391.96	802.20	29.41	119.10	6.10	360.75	113.52	6.10	3002.55	317.96
GASIFICATION-COAL, HIGH BTU	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HIGH S COAL-NO CONTROL	964.68	5951.13	71.39	302.48	16.28	720.19	225.45	13.78	15030.00	300.60
TOTAL	8361.95	10139.71	136.44	672.28	871.33	1300.29	6846.15	53.37	21790.05	624.93
					1980					
NATURAL GAS(CLEAN FUEL)	5486.27	156.68	2.35	88.13	847.57	94.30	0.00	0.00	0.00	0.00
DIST FUEL OIL(CLEAN FUEL)	728.19	440.72	3.07	56.94	36.58	3.72	6548.55	9.27	0.00	6.51
LOW S RESID-DOMESTIC	194.62	312.66	1.09	14.95	9.60	1.36	1873.48	6.53	0.00	1.96
LOW S RESID-IMPORTED	498.06	739.54	.92	36.99	7.17	0.00	0.00	10.65	0.00	0.00
GASIFICATION-OIL, HIGH BTU	95.67	6.96	.04	2.15	4.84	1.74	921.52	1.19	9.05	9.05
HIGH S RESID-NO CONTROL	210.45	1098.48	.39	15.63	3.03	0.00	0.00	4.50	0.00	0.00
LOW S COAL(CLEAN FUEL)	476.50	704.32	29.43	63.35	6.82	130.08	0.00	4.69	3438.50	0.00
CLEANABLE COAL(CLEAN FUEL)	402.55	823.88	30.21	122.32	6.27	370.50	116.59	6.27	3093.79	326.45
GASIFICATION-COAL, HIGH BTU	88.41	46.97	1.96	29.64	3.38	72.12	23.18	0.00	569.40	2223.50
HIGH S COAL-NO CONTROL	994.70	6074.66	72.87	308.76	16.62	735.14	230.13	14.06	15342.00	306.94
TOTAL	9097.43	10404.86	142.34	735.75	941.93	1408.36	9713.45	57.26	22842.65	2874.22

TABLE 24. (Continued)

SYSTEMS	EMISSIONS, THOUSANDS OF TONS									
	NOX	SO2	CO	PART	TOMA	SS	DS	TOMW	ASH	SLUDGE
					1985					
NATURAL GAS(CLEAN FUEL)	5808.44	165.88	2.49	93.30	897.39	99.52	0.00	0.00	0.00	0.00
DIST FUEL OIL(CLEAN FUEL)	903.28	549.71	3.83	71.02	45.53	4.64	8168.08	11.56	0.00	8.12
LOW S RESID-DOMESTIC	238.69	383.45	1.34	18.21	11.78	1.31	2297.66	8.13	0.00	2.28
LOW S RESID-IMPORTED	712.02	1057.22	1.32	52.88	10.35	0.00	0.00	15.22	0.00	0.00
GASIFICATION-OIL, HIGH BTU	125.55	10.19	.06	3.15	7.39	2.54	1350.43	1.74	13.26	13.26
HIGH S RESID-NO CONTROL	210.45	1098.48	.39	15.63	3.03	0.00	0.00	4.50	0.00	0.00
LOW S COAL(CLEAN FUEL)	451.50	745.51	31.15	63.89	7.22	137.71	0.00	4.97	4063.50	0.00
CLEANABLE COAL(CLEAN FUEL)	427.27	874.47	32.06	129.93	6.65	393.25	123.75	6.66	3273.05	346.59
GASIFICATION-COAL, HIGH BTU	366.03	213.82	8.94	134.93	15.38	328.32	105.51	0.00	2591.97	10121.70
HIGH S COAL-NO CONTROL	1042.47	6431.02	77.15	326.87	17.60	778.26	243.63	14.89	16242.00	324.84
TOTAL	10290.70	11529.85	158.73	909.70	1022.02	1745.55	12289.07	67.67	26193.78	10816.71
					2000					
NATURAL GAS(CLEAN FUEL)	7956.26	227.22	3.41	127.80	1229.23	136.32	0.00	0.00	0.00	0.00
DIST FUEL OIL(CLEAN FUEL)	1597.32	966.74	6.73	124.89	80.24	8.16	14364.56	20.34	0.00	14.28
LOW S RESID-DOMESTIC	271.74	436.54	1.52	20.73	13.41	1.49	2615.80	9.25	0.00	2.60
LOW S RESID-IMPORTED	841.80	1249.92	1.55	62.52	12.12	0.00	0.00	18.00	0.00	0.00
GASIFICATION-OIL, HIGH BTU	102.65	8.33	.05	2.57	5.90	2.09	1104.13	1.42	10.84	10.84
HIGH S RESID-NO CONTROL	210.45	1098.48	.39	15.63	3.03	0.00	0.00	4.50	0.00	0.00
LOW S COAL(CLEAN FUEL)	496.50	819.92	34.26	70.25	7.94	151.43	0.00	5.46	4468.59	0.00
CLEANABLE COAL(CLEAN FUEL)	469.64	961.19	35.24	142.70	7.31	432.25	136.02	7.31	3597.65	383.86
GASIFICATION-COAL, HIGH BTU	1282.59	749.22	31.33	472.80	53.99	1150.45	369.70	0.00	9082.38	35466.87
HIGH S COAL-NO CONTROL	1146.44	7072.46	84.84	359.47	19.35	855.89	267.93	16.37	17862.00	357.24
TOTAL	14375.39	13590.02	199.34	1399.38	1432.32	2738.06	18858.15	82.66	35021.37	35232.79

TABLE 25. TOTAL EMISSIONS FOR SYSTEMS IN THE ELECTRICAL SECTOR, SCENARIO 3

SYSTEMS	EMISSIONS, THOUSANDS OF TONS									
	NOX	SO2	CO	PART	TOMA	SS	DS	TOMW	ASH	SLUDGE
					1975					
NATURAL GAS(CLEAN FUEL)	1774.28	506.35	456.44	494.18	531.68	486.08	455.68	455.68	455.68	455.58
LOW S RESID-DOMESTIC	14.69	23.44	.28	1.28	.92	.28	141.60	.70	.20	.34
LOW S RESID-IMPORTED	623.28	925.46	1.16	46.29	8.97	0.00	0.00	13.33	0.00	0.00
CHEM ACTIVE FLUIDIZED BED	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HIGH S RESID-LIMESTONE SCRUB	17.54	9.19	.03	.06	.25	0.00	0.00	.38	0.00	345.00
HIGH S RESID-NO CONTROL	600.83	3136.16	1.11	44.62	8.65	0.00	0.00	12.85	0.00	0.00
LOW S COAL(CLEAN FUEL)	2242.50	3703.26	154.73	317.31	35.88	693.96	0.00	24.67	20182.50	0.00
CLEANABLE COAL(CLEAN FUEL)	243.65	498.66	18.28	74.03	3.80	224.25	70.57	3.80	1866.45	197.59
FLUIDIZED BED COMBUSTION-COAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GASIFICATION-COAL, LOW BTU	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LIQUEFACTION-COAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HIGH S COAL-LIMESTONE SCRUB	173.66	140.39	15.96	67.62	3.64	161.03	50.40	3.08	672.00	7711.20
HIGH S COAL-MGO SCRUB	43.41	35.10	3.99	16.90	.91	40.25	12.60	.77	168.00	16.80
HIGH S COAL-NO CONTROL	1164.93	7186.49	86.21	365.27	19.65	869.69	272.25	16.64	18150.00	363.00
TOTAL	6898.77	16164.52	738.21	1417.58	614.37	2465.51	1003.10	531.88	41494.83	9089.62
					1980					
NATURAL GAS(CLEAN FUEL)	1680.00	479.70	432.42	458.70	503.70	460.50	431.70	431.70	431.70	431.70
LOW S RESID-DOMESTIC	165.25	263.71	3.18	14.37	10.34	3.16	1592.95	7.89	2.26	3.44
LOW S RESID-IMPORTED	1297.77	1925.96	2.41	96.38	18.59	0.00	0.00	27.75	0.00	0.00
CHEM ACTIVE FLUIDIZED BED	16.15	45.16	.13	1.21	4.01	0.00	0.00	1.50	300.00	0.00
HIGH S RESID-LIMESTONE SCRUB	122.76	64.33	.23	.46	1.77	0.00	0.00	2.63	0.00	2415.00
HIGH S RESID-NO CONTROL	103.22	540.24	.20	7.81	1.51	0.00	0.00	2.25	0.00	0.00
LOW S COAL(CLEAN FUEL)	2636.00	4353.09	181.88	372.99	42.18	803.98	0.00	29.00	23724.00	0.00
CLEANABLE COAL(CLEAN FUEL)	338.99	693.79	25.44	103.00	5.28	312.00	98.18	5.28	2596.80	274.91
FLUIDIZED BED COMBUSTION-COAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GASIFICATION-COAL, LOW BTU	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LIQUEFACTION-COAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HIGH S COAL-LIMESTONE SCRUB	965.96	780.93	88.78	376.14	20.25	895.56	280.35	17.13	3738.00	42893.55
HIGH S COAL-MGO SCRUB	407.16	329.17	37.42	158.54	8.53	377.49	118.17	7.22	1575.60	157.56
HIGH S COAL-NO CONTROL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL	7736.17	9486.08	772.08	1589.61	616.25	2852.69	2521.35	532.34	32368.36	46176.56

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TABLE 25. (Continued)

SYSTEMS	EMISSIONS, THOUSANDS OF TONS NOX	SO2	CO	PART	TOMA	SS	OS	TOMW	ASH	SLUDGE
					1985					
NATURAL GAS(CLEAN FUEL)	1510.86	459.72	414.40	439.59	492.71	441.31	413.71	413.71	413.71	413.71
LOW S RESID-DOMESTIC	212.99	339.89	4.10	18.52	17.32	4.08	2053.13	10.16	2.91	4.95
LOW S RESID-IMPORTED	1557.33	2312.35	2.89	115.66	22.42	0.00	0.00	33.30	0.00	0.00
CHEM ACTIVE FLUIDIZED BED	89.75	225.80	.65	6.05	20.05	0.00	0.00	7.50	1500.00	0.00
HIGH S RESID-LIMESTONE SCRUB	220.97	115.79	.41	.82	3.19	0.00	0.00	4.72	0.00	4747.00
HIGH S RESID-NO CONTROL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LOW S COAL(CLEAN FUEL)	3636.00	6004.49	250.88	514.49	58.18	1108.98	0.00	40.00	32724.00	0.00
CLEANABLE COAL(CLEAN FUEL)	561.45	1149.09	42.13	170.60	8.75	516.75	162.61	9.75	4300.95	455.32
FLUIDIZED BED COMBUSTION-COAL	32.04	140.28	3.00	32.30	0.00	110.00	36.00	0.00	3460.00	48.00
GASIFICATION-COAL, LOW BTU	100.85	223.54	3.60	37.56	26.40	135.84	43.20	.48	2356.80	57.60
LIQUEFACTION-COAL	119.64	107.23	10.35	68.84	2.04	113.75	36.00	1.65	2404.65	48.00
HIGH S COAL-LIMESTONE SCRUB	837.27	676.89	76.95	326.02	17.55	775.25	243.00	14.95	3240.00	37179.00
HIGH S COAL-MGO SCRUB	458.33	370.53	42.12	178.47	9.61	424.92	133.02	8.13	1773.60	177.36
HIGH S COAL-NO CONTROL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00
TOTAL	9428.38	12125.61	851.49	1908.93	664.21	3631.88	3120.68	543.25	52176.62	42730.94
					2000					
NATURAL GAS(CLEAN FUEL)	1232.66	351.79	317.11	336.38	369.38	337.79	316.58	316.58	316.58	316.58
LOW S RESID-DOMESTIC	58.75	93.76	1.13	5.11	3.59	1.12	566.38	2.80	.80	1.37
LOW S RESID-IMPORTED	771.65	1145.76	1.43	57.31	11.11	0.00	0.00	16.50	0.00	0.00
CHEM ACTIVE FLUIDIZED BED	176.03	492.24	1.42	13.19	43.71	0.00	0.00	16.35	3270.00	0.00
HIGH S RESID-LIMESTONE SCRUB	175.37	91.90	.32	.65	2.52	0.00	0.00	3.75	0.00	3451.30
HIGH S RESID-NO CONTROL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LOW S COAL(CLEAN FUEL)	2553.60	4215.85	176.19	361.32	40.95	779.82	0.00	28.09	22981.50	0.00
CLEANABLE COAL(CLEAN FUEL)	554.39	1134.64	41.60	168.45	8.63	510.25	150.67	8.63	4246.85	449.59
FLUIDIZED BED COMBUSTION-COAL	240.30	1052.10	22.50	242.25	0.00	825.00	270.00	0.00	25950.00	360.30
GASIFICATION-COAL, LOW BTU	802.58	1778.97	28.65	298.91	210.10	1081.06	343.80	3.82	18756.20	459.40
LIQUEFACTION-COAL	696.17	893.58	86.25	573.71	17.00	947.92	300.00	13.75	20038.75	400.30
HIGH S COAL-LIMESTONE SCRUB	186.06	150.42	17.10	72.45	3.90	172.50	54.00	3.30	720.00	8262.00
HIGH S COAL-MGO SCRUB	286.22	231.40	25.31	111.45	6.00	265.36	83.07	5.38	1107.60	110.76
HIGH S COAL-NO CONTROL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL	9033.69	11633.41	729.01	2241.19	716.99	4919.73	2094.40	418.65	97388.28	13808.73

TABLE 26. SUMMARY OF TOTAL EMISSIONS FOR EACH SECTOR AND TOTAL EMISSIONS FOR ALL SECTORS-SCENARIO 3

SECTORS	EMISSIONS, THOUSANDS OF TONS									
	NOX	SO2	CO	PART	TOMA	SS	DS	TOMW	ASH	SLUDGE
					1975					
RESIDENTIAL AND COMMERCIAL	3197.65	2984.54	728.68	227.91	668.56	88.40	17322.90	30.77	1121.25	46.60
INDUSTRIAL	8361.95	10139.71	136.44	672.28	871.33	1300.29	5845.15	53.37	21790.05	624.93
ELECTRICAL	6898.77	16164.52	738.21	1417.58	614.37	2465.51	1003.10	531.88	41494.83	9089.62
TOTAL	18458.37	29288.76	1603.32	2317.77	2154.25	3854.21	25172.15	616.02	64406.13	9761.15
					1980					
RESIDENTIAL AND COMMERCIAL	3601.03	3083.52	706.45	251.16	714.99	143.18	20673.76	35.11	1521.20	1923.20
INDUSTRIAL	9097.43	10404.66	142.34	735.75	941.93	1408.36	9713.45	57.26	22842.65	2874.22
ELECTRICAL	7736.17	9486.08	772.08	1589.61	616.25	2852.69	2521.35	532.34	32368.36	46176.56
TOTAL	20434.63	22974.47	1620.88	2576.52	2273.18	4404.24	32908.56	624.72	56732.21	50973.94
					1985					
RESIDENTIAL AND COMMERCIAL	4056.19	3085.63	388.29	266.37	685.99	323.37	24816.32	40.84	2655.30	9919.99
INDUSTRIAL	10290.70	11529.85	158.73	909.70	1022.02	1745.55	12289.07	67.67	26183.78	10916.71
ELECTRICAL	9428.38	12125.61	851.49	1908.93	664.21	3631.88	3120.68	543.25	52176.62	42730.94
TOTAL	23775.26	26741.08	1398.52	3085.00	2372.22	5700.81	40226.07	651.76	81015.71	62567.64
					2000					
RESIDENTIAL AND COMMERCIAL	5031.98	3821.70	285.64	552.77	721.80	1060.19	32061.19	50.78	8393.74	32779.19
INDUSTRIAL	14375.39	13590.02	199.34	1399.38	1432.32	2738.06	18858.15	82.66	35021.37	36232.70
ELECTRICAL	8033.69	11633.41	720.01	2241.19	716.89	4919.73	2094.40	418.65	97388.28	13809.70
TOTAL	27441.05	29045.14	1204.99	4193.34	2871.02	8717.99	53013.74	552.10	140803.40	82820.57

TABLE 27. COMPARISON OF TOTAL EMISSIONS FOR SCENARIO 1 AND SCENARIO 3

	Total Emissions, Thousands of Tons									
	NO_x	SO_2	CO	Part	TOMA[a]	SS[b]	DS[c]	TOMW[d]	Ash	Sludge
						1975				
Scenario 1	18,409	29,525	1601	2318	2152	3854	25,172	616	64,773	9761
Scenario 3	18,458	29,288	1603	2318	2154	3854	25,172	616	64,406	9761
Difference, 3-1	49	-237	2	0	2	0	0	0	-367	0
						1980				
Scenario 1	20,222	18,478	1619	2577	2271	4404	32,908	624	46,405	71,926
Scenario 3	20,434	22,974	1621	2577	2273	4404	32,908	624	56,732	50,974
Difference, 3-1	212	4496	2	0	2	0	0	0	10,327	-20,952
						1985				
Scenario 1	23,537	18,737	1397	3048	2370	5700	40,226	651	67,774	92,702
Scenario 3	23,775	26,741	1398	3085	2372	5700	40,226	651	81,016	62,567
Difference, 3-1	238	8004	1	37	2	0	0	0	13,242	-30,135
						2000				
Scenario 1	26,954	20,658	1204	4160	2882	8717	53,013	552	127,863	102,650
Scenario 3	27,441	29,045	1204	4193	2871	8717	53,013	552	140,803	82,820
Difference, 3-1	487	8387	0	33	-12	0	0	0	12,940	-19,830

(a) Total organic material - air
(b) Suspended solids
(c) Dissolved solids
(d) Total organic material - water

ESTIMATION OF THE IMPACT OF PROJECTED EMISSIONS ON AMBIENT AIR QUALITY

Approach

To put into perspective the effect that projected energy requirements will have on ambient air quality, an analysis was made using the greater Indianapolis Air Quality Control Region (AQCR) as an example region. Battelle has spent close to two years developing an emission inventory for the Indianapolis AQCR. A recently completed study utilized this emission inventory to develop control strategies for meeting secondary SO_2 and particulate standards.

The Indianapolis AQCR was chosen for study because of the extensive data base already available. The point sources in this AQCR are smaller than might be considered typical; however, it was concluded that the analysis of an actual AQCR would be more meaningful than the analysis of a hypothetical "typical" AQCR.

Air quality is predicted using the Air Quality Display Model (AQDM), a multiple-source dispersion model. The AQDM uses as input data an emissions inventory and various meteorological parameters. Air quality is then predicted for a receptor grid and the predicted concentrations are printed in tabular form. Battelle has coupled several programs with AQDM so that BCL has the capability to predict emissions resulting from applying air pollution control laws, calculate the resulting air quality, and graphically display the receptor grid concentrations. Future growth of pollutant sources can also be accounted for by using growth factors with the emission inventory.

Characteristics of the Indianapolis AQCR

In order to analyze air quality prediction results, the greater Indianapolis Air Quality Control Region should be characterized with respect to types of sources.

The fuel-use mix in the Indianapolis AQCR is not typical in that coal is the predominant fuel. The 1971 inventory consisted of about 87.6 percent coal, 5.3 percent petroleum products, and 7.1 percent natural gas. This mix may be compared with the national combustion-fuel figures for 1971 which were: 27.7 percent coal, 25.0 percent petroleum products, and 47.3 percent natural gas.(1)

There are 434 sources inventoried in the Indianapolis AQCR; 227 sources are sources with emissions of more than 25 tons of any one pollutant per year, and the remaining 207 sources are referred to as area sources (emissions described in terms of tons per year for a given area of land). The data base was originally collected for 1970 and updated to include significant changes which occurred through 1972. For this study the inventory will be assumed to apply in 1971 for comparison with 1971 national figures.

A breakdown of the sources within the Indianapolis AQCR was derived from the source listing. The number of sources in each of seven arbitrary source categories is given in Table 28. For each source category the total emissions of SO_2 in tons per day are given together with the total contribution to the SO_2 concentration in $\mu g/m^3$ at Receptor 33, the receptor having the highest SO_2 concentration. These total emissions and ambient air quality contributions were obtained in a "base case" computer run in which all sources were assumed to burn clean fuels, i.e., low sulfur coal, low sulfur residual oil, distillate oil, or natural gas. This base-case run is referred to as the 1971 clean-fuels run.

Relative Ambient Air Quality Contributions From Small Sources and Large Sources

Previous studies have shown that, in general, small sources have a greater impact on ambient air quality in porportion to their emissions than do large sources.(12,13) The sources in the Indianapolis AQCR exhibit the same trend. Table 28 shows that the utility combustion group (20 to 440 MW) produced 156.9 tons SO_2 per day, or 78.1 percent of the total emissions, while contributing only 7.35 $\mu g/m^3$, or 15.8 percent, to the SO_2

TABLE 28. SUMMARY OF SOURCES IN INDIANAPOLIS AQCR-"CLEAN FUELS" RUN, 1971

Source Category	Number of Sources	Emissions		AAQ-R33		A/E	Mean Stack Ht.
		SO_2, T/D	E = % of Total	$\mu g/m^3$	A = %		
Utility Combustion 20-440 MW	11	156.9	78.1	7.35	15.8	.202	81 m
Industrial Combustion 10-40 MW equiv.	8	12.4	6.2	10.54	22.7	3.66	38 m
Industrial Combustion 5-10 MW equiv.	11	8.5	4.2	3.70	8.0	1.91	44 m
Industrial Combustion 1-5 MW equiv.	25	7.7	3.8	4.03	8.7	2.29	33 m
Industrial Processes	7	3.3	1.6	14.78	31.8	19.9	
Other Point Sources	165	3.1	1.5	1.96	4.2	2.80	
Area Sources	207	9.1	4.5	4.15	8.9	1.98	
Totals	434	201		46.52			

concentration at Receptor 33. On the other hand, industrial boilers in the 10-20 MW equivalent range produced 12.4 tons of SO_2 per day, or 6.2 percent of the total emissions, while contributing 10.54 $\mu g/m^3$, or 22.7 percent, to the total SO_2 concentration at Receptor 33.

The ratio, A/E, where A = the percent contribution to ambient air quality, and E = the percent of total emissions, was used in the previous studies(12,13) to show the relative effects of emissions from different sources. A large body of A/E data calculated from AQDM analysis of the New York, Philadelphia, and Buffalo AQCR's is presented in Reference 12. These data show that there is wide variation in individual A/E values but that average values for different types of sources are significantly different. For example, Reference 12 gives the following summary of New York AQCR SO_2 data where the A/E values are the mean values obtained for all receptors in the AQCR grid.

Source Category	Range of A/E	Mean A/E
Utility Power	0.13-1.56	0.49
Industrial Combustion	0.69-2.17	1.06
Area Sources	0.53-1.69	1.38

The A/E value less than unity for utility power sources shows that these sources contribute proportionally less to ambient air quality than to total emissions, while the A/E value greater than unity for area sources shows a relatively greater impact on ambient air quality from these smaller sources.

Values of A/E were calculated for each source category in the Indianapolis AQCR and are given in Table 28. The A/E for utility combustion is 0.2 and 5 of the 6 remaining categories have A/E values in the range of 1.9 to 3.7 in general agreement with the New York data. The very high value, A/E = 19.9, for industrial processing, is due to the presence of a sulfuric acid plant in close proximity to Receptor 33. This plant produces only 0.36 percent of the total SO_2 emissions in the AQCR but contributes more than 29 percent to the SO_2 concentration of Receptor 33.

It is obvious that A/E values calculated for a single receptor will be quite sensitive to the location of each source with respect to that receptor. A second calculation was carried out for Receptor 44, the fifth largest receptor. The resulting A/E values for each source category are presented in the following tabulation together with those for Receptor 33 for comparison.

Source Category	Receptor 44 A/E	Receptor 33 A/E
1	0.17	0.20
2	4.89	3.66
3	2.26	1.91
4	3.53	2.29
5	4.50	19.9
6	4.74	2.80
7	2.67	1.98

The A/E values for different receptors are different as expected; however, the conclusions regarding the relative impact of different source categories remain the same.

The disproportionate impact of small sources indicated by this analysis is related to the stack height and stems directly from the AQDM model. The basic equation states that the concentration of pollutant at a selected point is inversely proportional to an exponential function which includes the square of the stack height. This results in a much lower calculated concentration of pollutant for emissions from a tall stack as compared with the same emissions from a short stack. To demonstrate this relationship in the Indianapolis AQCR, the mean stack height is given in Table 28 for the first four source categories. The general trend, low A/E for tall stacks and high A/E for shorter stacks, is apparent. A plot of log (A/E) versus the square of the stack height shows the expected scatter but the correlation is clear.

Effects of Fuel Switching on Ambient Air Quality

In view of the conclusions reached in the foregoing analysis, the evaluation of the effect of projected energy requirements on ambient air quality must include consideration of source size. Therefore, ambient air quality calculations were carried out for the Scenario 1 projections, allocation of clean fuels to the residential/commercial and industrial sectors, and for the Scenario 3 projections, some dirty fuel burned in small sources because of restrictions on clean fuel allocation.

Basis for Ambient Air Quality Calculations

The Air Quality Display Model was used to calculate ambient air quality for the Indianapolis base case (1971 clean-fuels run). The results of this run were used to calculate the effects of increased fuel use, applied energy technology, and fuel switching as projected by Scenario 1 and Scenario 3. These calculations are based on the fact that the AQDM equation states that the concentration of pollutant at a selected point is directly proportional to the emission rate of the source. Thus, if the emission rate is increased by 20 percent, the pollutant concentration at any point, and therefore at all points, is increased by 20 percent. Similarly, if the emission rate of a number of sources is increased by 20 percent, the total pollutant concentration due to those combined sources is increased by 20 percent.

Hypothetical Case

To illustrate this approach and to demonstrate the effect of fuel switching, a hypothetical case is presented in Table 29. Consider a group of point sources producing 180 tons SO_2 per day and contributing 30 $\mu g/m^3$ of SO_2 at a given receptor, and a group of area sources with emissions of 80 tons SO_2 per day and an ambient air quality contribution of 30 $\mu g/m^3$. The A/E values in this case would be 0.7 and 1.7, respectively.

TABLE 29. COMPARISON OF POINT SOURCE AND AREA SOURCE CONTRIBUTION TO AMBIENT AIR QUALITY (AAQ)

Hypothetical Case

	Emissions of SO_2, T/D	AAQ of Receptor, $\mu g/m^3$
Hypothetical Case		
Point Sources	180	30
Area Sources	80	30
Totals	260	60
Shift 40 T/day of emissions from point sources to area sources		
Point Sources	140	23.3
Area Sources	120	45
Totals	260	68.3
Shift 40 T/day of emissions from area sources to point sources		
Point Sources	220	36.7
Area Sources	40	15
Totals	260	51.7

If clean fuel and dirty fuel were switched so that the point source emissions decreased by 40 tons per day to 140 tons per day and area source emissions increased by the same amount to 120 tons per day, the point source AAQ would decrease to 23.3 $\mu g/m^3$ (140/180 x 30) and the area source AAQ would increase to 45 $\mu g/m^3$ (120/80 x 30) to give a total AAQ of 68.3 $\mu g/m^3$. If the switch were made in the opposite direction, the same type of calculation gives a new total AAQ of 51.7 $\mu g/m^3$ as shown in Table 29. Thus, with the same total emissions, the AAQ varies from 51.7 to 68.3 $\mu g/m^3$ depending on the distribution of the emissions between the source types.

Modifications to Indianapolis AQCR

This approach was applied to projections for the Indianapolis AQCR corresponding to Scenario 1 and Scenario 3. Three modifications were made to simplify the calculations as follows:

(1) Only coal combustion was considered
(2) The sources were divided into two groups, utility sources and other sources
(3) Process sources were excluded.

As noted previously, the Indianapolis AQCR fuel mix includes nearly 88 percent coal and only 5 percent petroleum. Since natural gas combustion produces negligible SO_2 emissions, coal represents nearly 95 percent of the SO_2-producing fuel in the Indianaplis AQCR. For this reason, the total SO_2 emissions were attributed to coal burning and oil burning was neglected. The division of sources into two groups is based on the fact that the combustion sources other than the utility group have A/E ratios between 1.9 and 3.7. Thus, the impact of sources in this group on ambient air quality would be similar. Furthermore, allocation of fuels to categories within this group would be purely arbitrary, hence, not meaningful. The characteristics of the individual plants in the utility group are given in Table 30 for reference. The industrial process sources are noncombustion in nature. In the Indianapolis AQCR this group includes a sulfuric acid plant, three coke ovens, a catalytic petroleum cracker, a lead blast furnace, and a creosote plant. The SO_2 emissions from such

TABLE 30. CHARACTERISTICS OF UTILITY PLANTS IN INDIANAPOLIS AQCR

Source Number	Name	Size, MW	Type	Stack Height, ft	SO_2 Emission, ton/day	Contribution to Receptor 33, $\mu g/m^3$
1	H.T. Pritchard Station	105	Pulverized Coal	250	10.30	0.143
2	H.T. Pritchard Station	125	Pulverized Coal	250	12.39	0.163
3	H.T. Pritchard Station	175	Pulverized Coal	250	17.08	0.186
4	E.W. Stout Station	20	Underfed Stokers	134	2.41	0.849
5	E.W. Stout Station	55	Pulverized Coal	209	5.13	1.076
6	E.W. Stout Station	205	Pulverized Coal	250	30.38	3.339
7	E.W. Stout Station	450		565	57.77	0.519
8	Perry K Plant	65	Spreader Stokers	272	4.69	0.299
9	Perry K Plant	70	Pulverized Coal	272	5.22	0.306
10	Perry K Plant	80	Pulverized Coal	272	5.65	0.414
12	Noblesville Generation Station	230		217	5.92	0.057

sources would be constant as fuel use and energy technology are varied. Since these sources contribute over 30 percent to the AAQ of Receptor 33, their inclusion as a constant would tend to make the effects of fuel switching less distinct.

Projected Ambient Air Quality

The Indianapolis AQCR base-case, clean-fuels computer run for 1971 was modified on the basis of the foregoing considerations. The result gives the total coal use, total SO_2 emission rate, and total contribution to the SO_2 concentration at Receptor 33 for the electrical sector and for the other sectors combined. The projected AAQ for each year and each scenario were calculated by the following steps:

(1) The base-case values (coal use, SO_2 emission rate, and AAQ contribution) were increased by the coal-use growth factor obtained by dividing the projected national consumption of coal as fuel for the given year by the actual national coal use for 1971 using the Dupree and West data.(1)

(2) The newly projected coal use in each sector was broken down into high-sulfur coal, low-sulfur coal, and applied energy technology in proportion to the quantities projected for each in Tables 6, 7, and 8 for Scenario 1, and in Tables 19, 20, and 21 for Scenario 3.

(3) The SO_2 emissions rate for each coal type or combustion mode was calculated using the appropriate emission factors from Table 9.

(4) The new SO_2 emissions were summed for each sector.

(5) The new AAQ contribution from each sector was calculated on a proportional basis as illustrated in the hypothetical case.

(6) The new total AAQ was obtained by summing the new AAQ from each sector.

The details of each calculation are given in Appendix B and the results are given in Table 31. The difference in the predicted AAQ for Scenario 1 and Scenario 3 is large. The values for Scenario 3 are more than twice the values for Scenario 1 in each year. Since Scenario 3 includes some quantities of high sulfur coal in the nonelectrical sectors, this result is expected from the large difference in the A/E values for the electrical sector, 0.20, and for the other sectors, 1.9 to 3.7.* For each Scenario the predicted AAQ decreases from 1975 to 1980, reflecting the projected increase in the application of stack gas cleaning. The AAQ values rise again in 1985 and 2000 as a result of the projected increase in coal use.

One additional factor should be noted in connection with the relative seriousness of emissions from small sources versus large sources. There are some indications that sulfate may be a more critical air pollutant than SO_2.(14) If airborne residence time is a significant factor in the conversion of SO_2 to sulfate, then emissions from short stacks might contribute less sulfate as an air pollutant than tall stacks. These questions must be resolved before a final conclusion regarding the overall importance of emissions from short versus tall stacks can be reached.

Discussion of Results

The predicted ambient air quality results for Scenario 1 and Scenario 3 emphasize the importance of small sources in any emission control strategy. A successful strategy should include not only allocation of clean fuel to small sources but also provision of energy technology for small sources. It is necessary to implement both approaches because each has limitations. Allocation of clean fuels to small sources (as in Scenario 1) has only a minor effect on total SO_2 emissions but a dramatic

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*See Appendix B for a discussion of the impact of greater total emissions in Scenario 3 for the years 1980, 1985, and 2000.

TABLE 31. SUMMARY OF PREDICTED AMBIENT AIR QUALITY (INDIANAPOLIS AQCR)

		AAQ-Receptor 33, $\mu SO_2/m^3$(a)	
Year	Sector	Scenario 1	Scenario 3
1975	Electrical	16.3	12.0
	Other	26.9	93.2
	Total	43.2	105.2
1980	Electrical	6.4	6.6
	Other	31.1	90.1
	Total	37.5	96.7
1985	Electrical	7.4	9.3
	Other	40.3	102.0
	Total	47.7	111.3
2000	Electrical	9.0	10.7
	Other	54.6	130.6
	Total	63.6	141.3

(a) Process sources omitted.

effect on ambient air quality. Even so, in the sample case, the Indianapolis AQCR, the ambient air quality contribution from nonutility sources comprised 60 to 85 percent of the combustion-related ground-level concentration of SO_2 in Scenario 1. Thus, even if clean fuels could be allocated freely to small sources, it would be desirable to further limit emissions from small sources through application of some energy technology. A further limitation is that there exist some constraints on the allocation of clean fuels. The available data on the consumption of high- and low-sulfur fuels are not sufficiently detailed to permit the identification of all such constraints within the current program. However, some large blocks of "misplaced" clean fuel can be identified which include:

(1) Natural gas burned under large, electrical-generation steam boilers operated by industry as well as by utilities. Such use involves long-term gas contracts or even outright ownership of the gas field by the company.

(2) Low-sulfur coal burned under utility boilers. Again such use may involve long-term binding contracts, or utility company ownership of mines producing low sulfur coal.

The actual extent and nature of such constraints to clean-fuels allocation should be determined in order to develop methods for improving the flexibility and to accurately assess the magnitude of the emissions control problem remaining for small sources.

The limitation of energy technology in this context lies in the fact that most of the technologies under development are applicable primarily to large sources. The question of applicability is discussed further in the technology assessment section. Two conclusions may be drawn from these considerations.

(1) The technologies for control of emissions from large sources should be perfected and applied as rapidly as possible to free clean fuels for use in small sources.

(2) Energy technology applicable to small sources must be developed as rapidly as possible.

TECHNOLOGY ASSESSMENT

Approach

The assessment of the potential role of the energy technologies in the achievement of the national goals of meeting energy demand and maintaining ambient air quality is difficult because it requires consideration of a number of diverse factors which then must be related and compared in a meaningful way. The approach taken to this assessment involved the following steps:

(1) The development of assessment criteria
(2) The evaluation of each technology with respect to each assessment criterion
(3) The conversion of the evaluation to a rating scale
(4) The compilation of aggregate ratings for each technology, both with and without weighting of the criteria
(5) The ranking of the technologies based on the aggregate ratings.

The mechanics of the assessment involve methodology developed at Battelle for environmental impact assessment modified somewhat for application to technology assessment.

Assessment Criteria

A set of six criteria were employed in the assessment of the energy technologies as follows.

(1) Residual emissions
(2) Projected availability of the technology
(3) Applicability of the technology to various fuels and to various markets
(4) Cost of the applied technology
(5) Energy efficiency of the technology
(6) Probability of successful development.

The energy technologies under consideration have differing potential for minimizing air pollutant emissions. This variability was expressed in terms of the residual air emission which are expected to result from the application of the technology. In each case, the air emissions resulting from the entire fuel/energy cycle, including extraction, transportation, processing, and utilization were considered.

In view of the urgency of the related energy and environmental problems, the projected availability of a given technology is an important criterion in the assessment of its potential role. The factors of date of commercialization and the subsequent rate of implementation of the technology are components of the availability consideration. These questions involve the current stage of development and commercialization and the complexity of the process.

The applicability of the technology was evaluated with respect to the types and availability of fuels appropriate to the technology, and to the various markets which could be served by the technology.

The cost factor is complex and involves the capital requirements, the operating cost of the technology, i.e., the incremental cost of energy due to the application of the technology, comparative costs of competitive technologies, and development costs. Another consideration is the question of utilization of capital within the United States rather than investment in foreign-based operations.

The criterion of energy efficiency includes losses in fuel processing, energy requirements in the application of the technology, and the potential of some technologies to be coupled with advanced power cycles thus increasing overall efficiency.

The probability of success was evaluated on the basis of the amount of existing data, the complexity of the technology, and the degree of departure from existing technology.

The question of system reliability is an important factor which was considered in the assessment process. It was not established as a separate criterion, however, because reliability is very closely associated with the categories of availability and probability of successful development. It was assumed that reliability must be established before a technology is considered commercially available. Similarly, reliability is inherent in evaluating the probability of successful development.

There are, of course, interrelationships between other assessment criteria. For example, the complexity of the proposed technology is considered in probability of successful development as well as in availability through the cost and risk factors which affect the probability that needed work will be done to complete the development.

Technology Evaluation

The second step in the assessment procedure was to develop an evaluation of each technology with respect to each of the six assessment criteria. A quantitative evaluation was employed wherever possible, otherwise qualitative categories for evaluation were developed. The results of this evaluation are summarized in Table 32. This summary includes ten categories of energy technologies, and the basic assessment was made for these ten. Some of these categories include more than one approach. Comparisons of different processes within an energy technology are pointed out in the various evaluations. The derivation and significance of the evaluations in each assessment category are discussed in the following sections.

Residual Emissions

The data in Table 32 which characterize the residual emissions for each technology were derived from the total emissions given in Tables 10, 11, and 12, which, as discussed previously, indicate total emissions for the entire fuel/energy system. Thus the data in Table 32 take into account the air emissions from each module represented in each fuel/technology system as defined in Table 8. The residual emissions in Table 32 are expressed in units of thousands of tons per trillion Btu. (This unit is equal to two pounds per million Btu.) A sample calculation will serve to illustrate the derivation of the data. The quantity of cleanable coal projected for 1975 is given in Table 6 as 1,110 x 10^{12} Btu. The total air pollutant emissions from the extraction, physical cleaning,

TABLE 32. ENERGY TECHNOLOGY EVALUATION MATRIX

Energy Technology	Total System Residual Emissions, 10^3 ton/10^{12} Btu	Availability		Applicability		Cost		Energy Efficiency	Probability of Successful Development$^{(j)}$
		Year	Rate	Fuels	Sector Markets$^{(a)}$	Capital, \$/kw	Operating, ¢/10^6 Btu		
Physical Coal Cleaning	1.214	Now	1	Coal	All	$2.3^{(b)}$	$6.6^{(b)}$	.88	E
Chemical Coal Cleaning	1.359	1978	2	Coal	All	$16\text{-}22^{(c)}$	$26^{(c)}$	.95	A-3
Resid Desulfurization	1.015	Now	1	Oil	All	$17^{(d)}$	$45^{(d)}$	.90	E
Coal Refining (liquefaction)	1.026	1980	3	Coal	E+I	$80^{(e)}$	$60^{(e)}$	.75	B-2
Coal Gasification, low Btu	0.817	1978	3	Coal	E+I	$90^{(f)}$	$50^{(f)}$	.70	B-2
Coal Gasification, high Btu	0.996	1977	3	Coal	R/C	$117\text{-}197^{(g)}$	$60^{(g)}$	.65	B-1
Stack Gas Cleaning, throwaway	0.718	Now	1	Both	E+I	$25\text{-}75^{(h)}$	$25^{(h)}$	.95	A-1
Stack Gas Cleaning, by-product	0.718	1974	1	Both	E+I	$25\text{-}75^{(h)}$	$25^{(h)}$	.95	A-1
High-Pressure Fluidized-Bed Combustion of Coal	0.520	1977	2	Coal	E+I	$5\text{-}25^{(i)}$	$20^{(i)}$	1.00	A-3
Atm. Pressure Chemically Active Fluidized-Bed Combustion of Oil	0.334	1977	2	Oil	E+I	$5\text{-}25^{(i)}$	$20^{(i)}$	1.00	A-3

Footnotes to Table 32

(a) E = Electrical Sector, I = Industrial Sector, R/C = Residential and Commercial Sector.

(b) Capital costs for physical coal cleaning plants were estimated in Reference 15 to be $5.6 and $6.3 million for two modifications of a 1000 T/hour plant. These estimates were converted to $/kw and the 1966 costs escalated to 1972 costs by means of the Marshall Stevens index. The average of the values, $2.17/kw and $2.44/kw, was taken. The value given for operating cost was taken from Reference 2, page 333.

(c) Capital and operating costs given are Battelle estimates for hydrothermal chemical coal cleaning.

(d) The capital cost of hydrodesulfurization of residual oil was reported in Table 15, page 97 of Reference 16. Operating cost is estimated at 43.6 cents per million Btu on page 23 of Reference 16. Page 99 of the same reference shows costs for other modifications up to 48.4 cents/million Btu. A value of 45 cents/million Btu was selected.

(e) Capital and operating costs were taken from Reference 2, page 364. The estimate for operating cost includes the value of the coal lost in processing but not the cost of the coal converted to product.

(f) Capital costs of $82/kw were estimated for the Wellman-Galusha low Btu process in Reference 16, page 91. Other estimates of capital costs for other low Btu systems range from $70 to $135 per installed kw. A value of $90/kw was taken. Operating cost estimates range from 45 to 70 cents per million Btu. A conservative value of 50 cents per million Btu was chosen.

(g) Capital costs were taken from Reference 2, page 381. The capital cost for a Lurgi high Btu plant was estimated in Reference 17 as $134/kw which is within the range given. The cost of high Btu gas at a Lurgi plant was estimated in Reference 17 to range from $1 to $1.20 per million Btu for coal costing $7 per ton. Subtracting this coal cost gives a range of 50 to 70 cents per million Btu. The mean of this range was chosen.

(h) Capital and operating costs for stack gas cleaning were taken from Reference 2, pages 409 and 394. The operating cost entered in the table is a mean value.

(i) Capital and operating costs for fluidized-bed combustion of coal and oil were taken from Reference 2, pages 416 and 423.

(j) See text for definition of categories.

transportation, and combustion of that quantity of coal are given in Table 11 as follows: NO_x - 391.96, SO_2 - 802.2, CO _ 29.4, particulate - 119.1, and total organic material - 6.1 thousand tons. Each of these quantities was divided by 1,110 trillion Btu to give the following system emissions: NO_x - 0.353, SO_2 - 0.723, CO - 0.026, particulate - 0.107, and total organic material - 0.005 thousand tons per trillion Btu. The total of these air emissions, 1.214 thousand tons per trillion Btu, was entered in the residual emissions column of Table 28 for the physical coal cleaning technology.

The chemical coal cleaning system was not included in the projected total emissions calculations. The residual emissions value in Table 32 was therefore derived from data given in Reference 2 with correction to 1 percent sulfur in the chemically cleaned coal. The other residual emissions data in Table 32 were calculated as illustrated for physical coal cleaning. In addition the residual emissions for a reference system, eastern high-sulfur coal burned without sulfur dioxide control, were calculated in the same manner to be 2.908 thousand tons per trillion Btu.

Availability

Technology availability was evaluated first in terms of the estimated year of commercial availability, defined as the year during which 1 year of successful operation on a 100-MW plant is achieved. The years entered in Table 32, under Availability - Year, represent a concensus of opinion regarding the achievement of such a successful demonstration. A second factor to be considered with respect to availability is the rate at which the technology will be implemented after commercialization. A major factor affecting the rate of implementation is the complexity of the process. A highly complex process, requiring a longer lead time for fabrication of components and construction, and being more highly capital intensive will lead to a lower implementation rate. These considerations were combined and the technologies evaluated with respect to three categories defined as follows: Rate Category 1, those technologies now in commercial use and those which represent a relatively low degree of complexity; Rate Category 2, those technologies based on existing technology but requiring unusual process conditions thus representing an intermediate degree of complexity; Rate Category 3, highly complex processes. The technology evaluations based on these three categories are given in Table 32 under Availability - Rate.

Applicability

Applicability was evaluated qualitatively with respect to the type of fuel used and to the sector markets served. The entries under Applicability in Table 32 reflect the applicability of each technology to coal, to oil or to both fuels and the consuming sectors expected to be markets for each technology.

Cost

The energy technologies were evaluated with respect to two cost categories: capital requirements and operating costs. The capital costs given in Table 32 are expressed in dollars per kilowatt of electrical generating capacity. For fuel cleaning and fuel conversion technologies, the plant output in Btu was converted to the equivalent power plant output from that quantity of fuel by the ratio 60×10^6 Btu/year = 1 kw of installed capacity. This conversion ratio assumes a heat rate of 10,000 Btu/kwhr and a load factor of 68 percent.

The operating costs given in Table 32 are expressed in cents per million Btu. The operating costs refer only to process costs and do not include the cost of the fuel processed or burned. Thus these costs represent the incremental energy cost added through the application of the technology. The bases for the cost estimates given in Table 32 are summarized in footnotes to the table.

A third factor in the cost criterion is the cost of research and development. Because this is a less significant factor over the long term than the other two and because estimates of developments costs are quite uncertain, no attempt was made to formally include development costs in the assessment.

Energy Efficiency

The energy efficiencies given in Table 32 reflect energy loss as compared with a conventional system and thus represent energy penalties attending the application of each technology. For fuel cleaning and fuel conversion processes, the inefficiency consists largely of fuel loss, either through material losses in the processing, or through fuel burned for process heat or both. For the stack gas cleaning technologies, the inefficiency represents the parasitic energy required to operate the cleaning process. The efficiency value of unity entered for the fluidized-bed technologies reflects the potential for achieving a thermal efficiency from fluidized bed/generator coupling equal to or greater than that from conventional steam boilers.

The energy efficiency data given in Table 32 were taken from Reference 2, with the exception of the value for residual oil desulfurization which was calculated from data given in Table 13, page 94 of Reference 16.

Probability of Successful Development

The probability of successful development was evaluated categorically. Five categories were established to reflect the current status of the development and the degree of departure from conventional technology. These categories are defined as follows:

E = existing technology
A-1 = modest extension of existing technology
A-2 = moderate extension of existing technology
A-3 = significant extension of existing technology
B-1 = requires moderate amount of technology
B-2 = requires significant new technology.

Each technology was evaluated with respect to these five categories as indicated in Table 32.

Technology Rating

The evaluations of each technology within each assessment criterion compiled in Table 32 represent diverse kinds of information. Some evaluations are quantitative, with different units for different criteria; others are qualitative or categorical. To provide a means for combining these evaluations into an overall assessment, the evaluations were converted to a rating scale. The methodology was adapted from an approach developed at Battelle for environmental impact assessment.(18,19)

The evaluations were converted to ratings through the Technology Rating Function illustrated in Figure 1. The Technology Rating Factor, with values from 0-10, is read from the ordinate for various values of the assessment parameter given on the abscissa. The use of the Technology Rating Function results in a normalization of the quantitative evaluations which resolves the problem caused by the use of different units in different

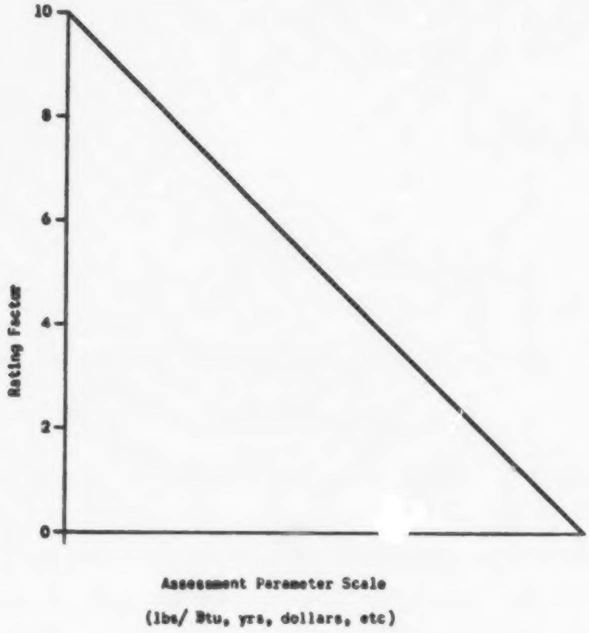

FIGURE 1. GENERALIZED TECHNOLOGY RATING FUNCTION

evaluations. In addition, the Technology Rating Function approach provides a means for quantifying the qualitative or categorical evaluations.

Residual Emissions Rating

The Technology Rating Function for the residual-emissions criterion is shown in Figure 2. The abscissa represents the residual emissions expressed as thousands of tons per trillion Btu. The residual emissions of the system, strip mining of Eastern coal-rail transport-conventional boiler without sulfur dioxide control (2.908 thousand tons per trillion Btu), were selected as the reference point for zero Rating Factor Conversely, zero emissions were set equal to a Rating Factor of ten. The residual emission Rating Factor for each technology is the ordinate value corresponding to the residual emission value for each technology obtained from Table 32. For example, the total residual emissions given in Table 32 for the physical coal cleaning technology are 1.214 thousand tons per

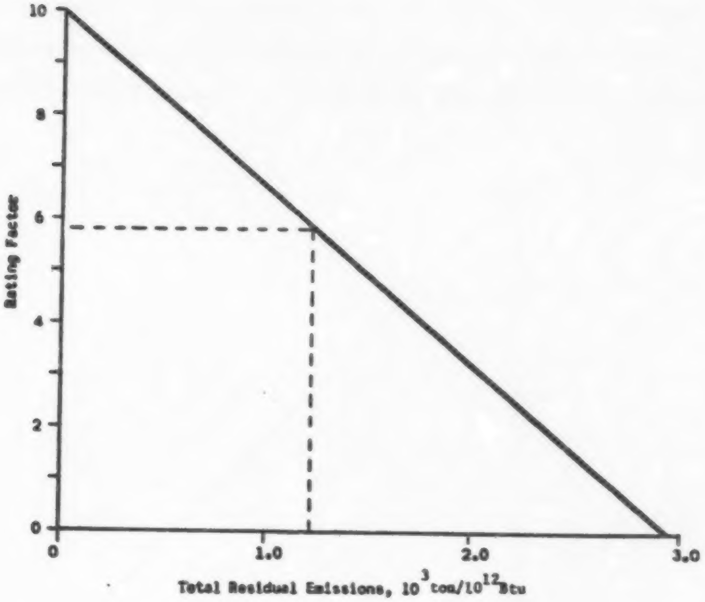

FIGURE 2. TECHNOLOGY RATING FUNCTION FOR AIR EMISSIONS

trillion Btu. As shown by the dotted lines in Figure 2, the corresponding Rating Factor is 5.8. In this manner, the residual emissions Rating Factors were determined for each technology. The resulting factors are given in descending order in the following tabulation.

Energy Technology	Residual Emissions Rating Factor
Chemically active fluidized bed, oil	8.9
High pressure fluidized bed, coal	8.2
Stack gas cleaning, by-product	7.5
Stack gas cleaning, throwaway	7.5
Coal gasification, low Btu	7.2
Coal gasification, high Btu	6.6
Resid desulfurization	6.5
Coal refining (liquefaction)	6.5
Physical coal cleaning	5.8
Chemical coal cleaning	5.3

Availability Rating

The Technology Rating Function for availability based on year of first commercialization is shown in Figure 3. A zero Rating Factor was assigned to the year 1985 and a Rating Factor of 10 was assigned to the present year. The second evaluation in the availability criterion, i.e., rate of availability, was introduced by applying the following corrections to the Rating Factors obtained from Figure 3: Rate Category 1 - no correction; Rate Category 2 - 0.3 correction; and Rate Category 3 - 0.6 correction.

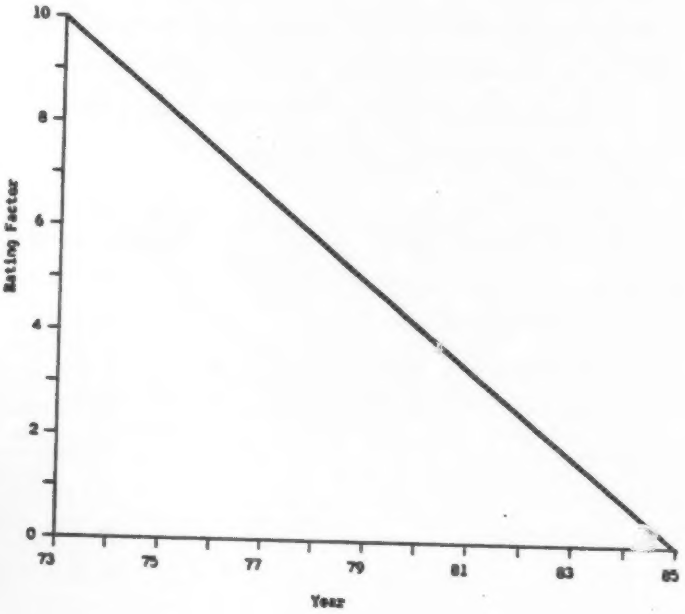

FIGURE 3. TECHNOLOGY RATING FUNCTION FOR TECHNOLOGY AVAILABILITY

The availability Rating Factors are:

Energy Technology	Rating Factor for Year of Availability	Correction for Rate of Availability	Net Rating Factor
Physical coal cleaning	10	None	10
Resid desulfurization	10	None	10
Stack gas cleaning, throwaway	10	None	10
Stack gas cleaning, by-product	9.2	None	9.2
Chemically active fluidized bed, oil	6.7	-0.3	6.4
High pressure fluidized bed, coal	6.7	-0.3	6.4
Coal gasification, high Btu	6.7	-0.6	6.1
Chemical coal cleaning	5.8	-0.3	5.5
Coal gasification, low Btu	5.8	-0.6	5.2
Coal refining (liquefaction)	4.2	-0.6	3.6

Applicability Rating

Both components of the evaluation of the applicability of energy technologies are categorical in nature. The Technology Rating Function shown in Figure 4 for fuel applicability is based on the rationale that energy technologies applicable to both coal and oil utilization should be rated higher than those applicable to either fuel alone. Further, in view of the nation's relative abundance of coal and scarcity of oil, the technologies applicable only to oil were downgraded with respect to those applicable only to coal. The location of these categories along the abscissa of Figure 4 is arbitrary but based on the above considerations.

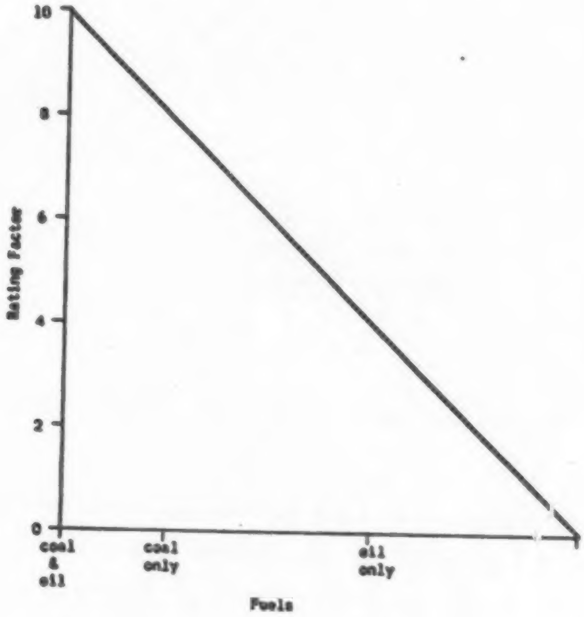

FIGURE 4. TECHNOLOGY RATING FUNCTION FOR FUEL AVAILABILITY

The Technology Rating Function shown in Figure 5 for market applicability was constructed in a similar fashion. The location of the three categories along the abscissa was based on the greater weight given to the electrical and industrial sectors which make up 70-72 percent of the total demand throughout the period to 2000.

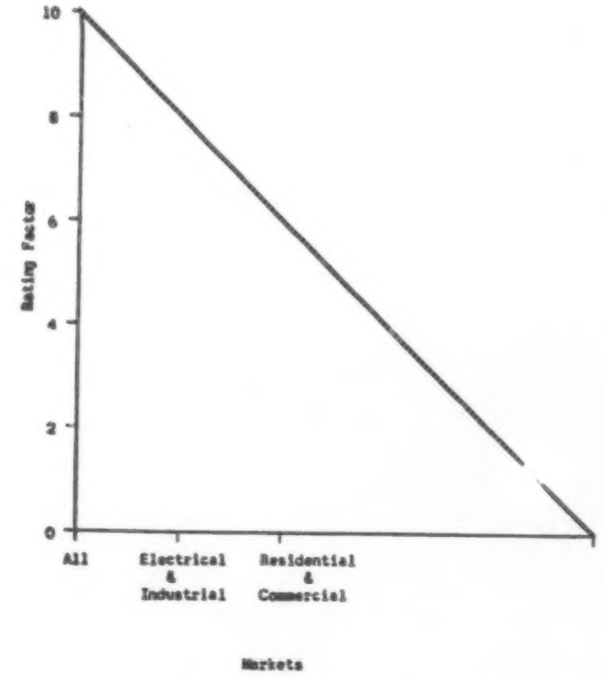

FIGURE 5. TECHNOLOGY RATING FUNCTION FOR MARKET APPLICABILITY

The Rating Factors for each technology were determined from Figures 4 and 5 and the mean of the two values taken as the composite Rating Factor for the applicability criterion. The results are as follows:

Energy Technology	Rating Factor for Fuel Applicability	Rating Factor for Market Applicability	Mean Rating Factor
Physical coal cleaning	8	10	9
Chemical coal cleaning	8	10	9
Stack gas cleaning, throwaway	10	8	9
Stack gas cleaning, by-product	10	8	9
Coal refining (liquefaction)	8	8	8
Coal gasification, low Btu	8	8	8
High pressure fluidized bed, coal	8	8	8
Resid desulfurization	4	10	7
Coal gasification, high Btu	8	6	7
Chemically active fluidized bed, oil	4	8	6

Cost Rating

The Technology Rating Function for capital cost is shown in Figure 6 and that for operating cost is shown in Figure 7. A capital cost of $300/kw was assigned a zero Rating Factor in Figure 6, and an operating cost of $1 per million Btu was assigned a zero Rating Factor in Figure 7. The Rating Factors were determined separately for capital and operating cost and the resulting values averaged to give the overall Rating Factor. Where ranges are given in Table 32 for capital cost, the mean of the range was used to determine the Rating Factor. The results are as follows.

Energy Technology	Rating Factor, Capital Cost	Rating Factor, Operating Cost	Mean Cost Rating Factor
Physical coal cleaning	9.9	9.3	9.6
High pressure fluidized bed, coal	9.5	8.0	8.8
Chemically active fluidized bed, oil	9.5	8.0	8.8
Chemical coal cleaning	9.4	7.4	8.4
Stack gas cleaning, throwaway	8.3	7.5	7.9
Stack gas cleaning, by-product	8.3	7.5	7.9
Resid desulfurization	9.4	5.5	7.5
Coal gasification, low Btu	7.0	5.0	6.0
Coal refining (liquefaction)	7.3	4.0	5.7
Coal gasification, high Btu	4.8	4.0	4.4

Energy Efficiency Rating

The Technology Rating Function for energy efficiency is shown in Figure 8 where 50 percent efficiency was assigned a zero Rating Factor. The resulting values are as follows.

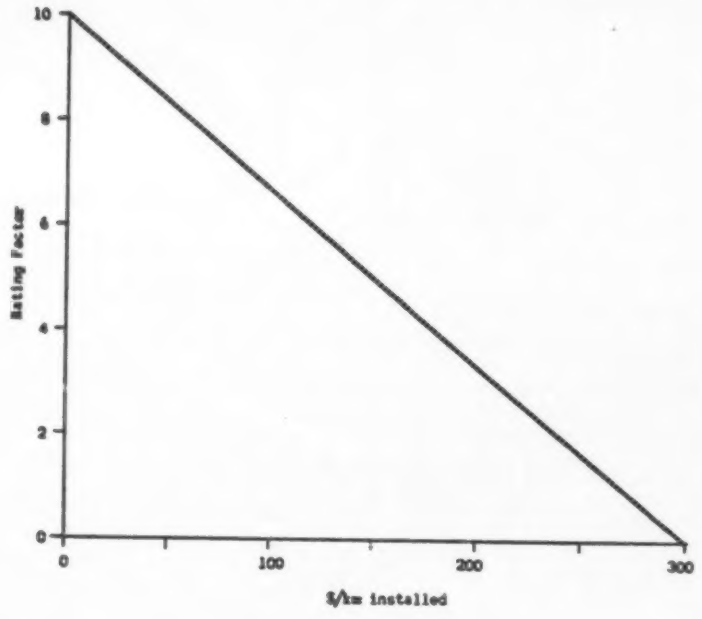

FIGURE 6. TECHNOLOGY RATING FUNCTION FOR CAPITAL COSTS

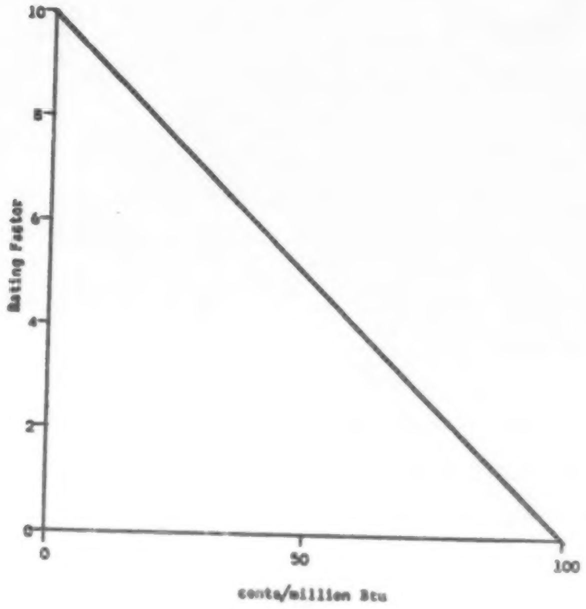

FIGURE 7. TECHNOLOGY RATING FUNCTION FOR OPERATING COSTS

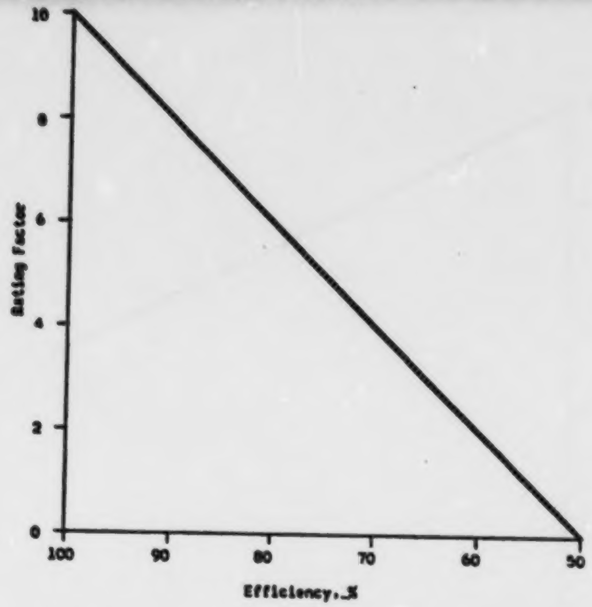

FIGURE 8. TECHNOLOGY RATING FUNCTION FOR EFFICIENCY

Energy Technology	Energy Efficiency Rating Factor
High pressure fluidized bed, coal	10
Chemically active fluidized bed, oil	10
Chemical coal cleaning	9
Stack gas cleaning, throwaway	9
Stack gas cleaning, by-product	9
Resid desulfurization	8
Physical coal cleaning	7.6
Coal refining (liquefaction)	5
Coal gasification, low Btu	4
Coal gasification, high Btu	3

Probability of Successful Development Rating

The Technology Rating Function for probability of successful development is shown in Figure 9. The evaluation categories are located along the axis on the basis of the relative probability of success judged for each category. The resulting Rating Factors are as follows.

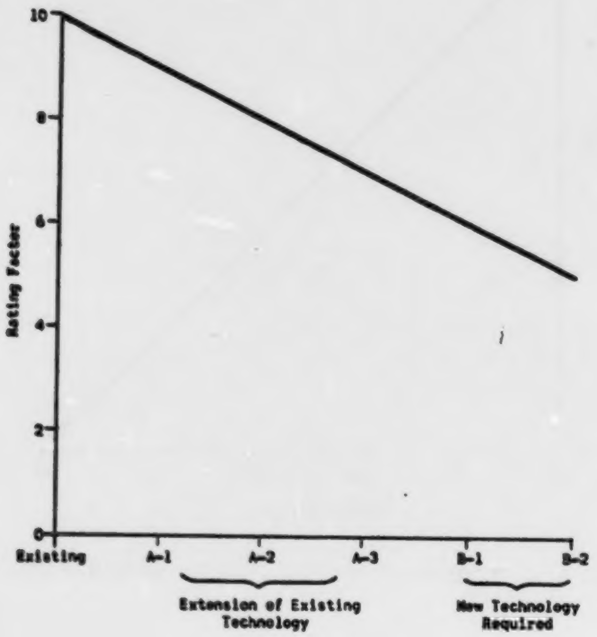

FIGURE 9. TECHNOLOGY RATING FUNCTION FOR PROBABILITY OF SUCCESSFUL DEVELOPMENT

Energy Technology	Probability of Success Rating Factor
Physical coal cleaning	10
Resid desulfurization	10
Stack gas cleaning, throwaway	9
Stack gas cleaning, by-product	9
Chemical coal cleaning	7
High pressure fluidized bed, coal	7
Chemically active fluidized bed, oil	7
Coal gasification, high Btu	6
Coal refining (liquefaction)	5
Coal gasification, low Btu	5

Aggregation of Technology Ratings

Unweighted Summation

The overall technology assessment including all criteria was first made by summing the individual criteria ratings for each technology. The sums thus obtained reflect the relative potential of the various technologies assuming that all of the criteria are equally important. All of the ratings are compiled in Table 33 in which the technologies are listed in ranked order according to their aggregate ratings.

Weighted Summations

To incorporate the relative importance of the assessment criteria in judging the potential role of energy technologies, a second aggregation was carried out. Each rating was first multiplied by a weighting factor chosen to reflect the relative importance of the criteria; then the products were summed to obtain the weighted aggregate rating.

The weighting factors were obtained by quantifying the subjective value judgments of a panel of six Battelle scientists active in the air pollution control field. An iterative procedure was used with controlled feedback of intermediate results to arrive at a group consensus. Each member was asked to list the six criteria in order of importance as measures of the potential role of energy technology in satisfying our energy demands with minimum air pollution. Each member then made successive pairwise comparisons between contiguous elements to determine for each element pair the ratio of importance. For example, the criterion ranked second was compared to the first to determine how much less important the second is to the first. This relative importance was expressed as a ratio greater than zero, and less than or equal to one. The process was continued between the third and the second, the fourth and the third, etc. The output from this procedure was a weighted list of the criteria for each member of the panel. The weighting factors thus developed were averaged to yield the first set of weights. The results were as follows.

TABLE 33. ENERGY TECHNOLOGY RATING MATRIX

Energy Technology	Criteria Rating, R						Unweighted Aggregate Rating, ΣR	Weighted Aggregate Rating, $\Sigma W_i R$	Normalized Weighted Rating
	Residual Emissions	Availability	Applicability	Cost	Energy Efficiency	Probability of Success			
Stack Gas Cleaning, throwaway	7.5	10	9	7.9	9	9	52.4	405.5	52.2
Physical Coal Cleaning	5.8	10	9	9.6	7.6	10	52.0	403.2	51.9
Stack Gas Cleaning, by-product	7.5	9.2	9	7.9	9	9	51.6	398.7	51.3
Resid Desulfurization	6.5	10	7	7.5	8	10	49.0	384.0	49.4
High Pressure Fluidized-Bed, coal	8.2	6.4	8	8.8	10	7	48.4	378.9	48.8
Chemically Active Fluidized Bed, oil	8.9	6.4	6	8.8	10	7	47.1	377.9	48.7
Chemical Coal Cleaning	5.3	5.5	9	8.4	9	7	44.2	335.3	43.2
Coal Gasification, low Btu	7.2	5.2	8	6.0	4	5	35.4	273.7	35.2
Coal Refining (liquefaction)	6.5	3.6	8	5.7	5	5	33.8	257.1	33.1
Coal Gasification, high Btu	6.6	6.1	7	4.4	3	6	33.1	255.9	33.0

Assessment Criterion	Mean Weighting Factor	Standard Deviation
Residual Emissions	19.0	12.7
Availability	13.4	10.7
Cost	12.9	5.4
Applicability	12.4	7.2
Probability of Success	12.2	10.3
Efficiency	11.4	9.8

These results show that the members of the group differed widely in their evaluation of the relative importance of the criteria. The large standard deviation for most of the criteria shows that some members gave a given criterion a large weight while others gave the same criterion a small weight. The averaging process smoothed these out to leave the weights nearly the same from the second criterion to the last, i.e., the group consensus after the first weighting was that the criteria are of nearly equal importance. A consultant asked to rank the criteria in the same fashion said that he felt that they were all of equal importance, thus tending to support the first group consensus. A second iteration was performed in which the panel was given the group weights and the standard deviations. Each member repeated the scaling procedure and the resulting weights again averaged with the following results

Assessment Criterion	Mean Weighting Factor	Standard Deviation
Cost	16.8	3.2
Emissions	16.3	7.8
Availability	14.3	9.0
Probability of Success	12.5	10.5
Efficiency	12.0	5.0
Applicability	6.7	6.1

The standard deviation, although smaller than those of the first iteration, are still large showing that considerable difference of opinion still remained among the panel regarding the relative importance of the criteria.

The mean weighting factors from the second iteration were normalized to a scale of 1-10 and rounded to the nearest 0.5. The final weights were as follows.

Assessment Criterion	Final Weighting Factor, Wf
Residual Emissions	10
Cost	10
Availability	8.5
Probability of Success	7.5
Efficiency	7
Applicability	4

It should be stressed that the weights obtained represent an average of the rather diverse opinion of one panel. The results were used only to examine the effects of weighting the ratings and they are not presented as an absolute scale of relative importance. These weights were employed to compute the weighted aggregate rating values entered in Table 33. For easier comparison with the unweighted sums, the weighted totals were normalized as shown in the last column of Table 33.

Comparison of the weighted and unweighted ratings shows that the rank order of the technologies did not change and the differences in the aggregate ratings by the two methods are small.

Discussion of the Technology Assessment

Examination of the total weighted technology ratings given in Table 33 shows that there are three rather distinct groupings of technologies. The technologies in the highest ranked group, including both stack gas cleaning technologies and physical coal cleaning, have essentially equivalent ratings. The technologies in the second group, consisting of residual oil desulfurization and the two fluidized-bed technologies, are nearly equivalent but are 3 to 5 points lower in rating than the first group. The third group includes the three coal conversion processes. The ratings for this group are 12-14 points below those for the second group. Chemical coal cleaning is rated between the second and third groups.

The stack gas cleaning processes combine good emission control, early projected availability, and intermediate cost to achieve their high ratings. Physical coal cleaning and residual oil desulfurization are less effective in emission control but the fact that they are both existing technologies is an offsetting consideration. The relatively low cost of physical coal cleaning raises that technology into the highest rated group. The coal conversion processes, on the other hand, exhibit less effective air emission control, when the entire system is considered, later availability, higher cost, and lower energy efficiency than the rest of the technologies which accounts for their comparatively low ratings.

The comparison of the weighted and unweighted aggregate technology ratings in Table 33 is interesting. As noted previously, the rank order of the technologies remained the same when the technology ratings were weighted according to a scale of relative importance of the assessment criteria. This result emphasizes the fact that the technologies near the top of the list are highly rated in most of the criteria while those near the bottom of the list are less highly rated in most of the criteria. Another contributing factor is that the weighting factors used did not differ greatly, the first five varying only between 7 and 10. However, given the generally high criteria ratings of the top group and the generally low ratings of the bottom group, the rank order of technologies could be expected to remain unaffected unless highly disproportionate, and thus unrealistic, weighting factors were used.

The technology assessment was designed to incorporate a number of factors into an unbiased evaluation of the various technologies with respect to their overall potential. It was not possible to accurately reflect all the factors involved, and in some cases there will be special considerations which may override the factors which were specifically included in the assessment. As one example, the widespread use of natural gas for home heating and the abundance of coal combine to make the conversion of coal into a substitute natural gas a highly desirable, if not mandatory, technology for the future. Thus, although the high Btu gasification technology is ranked last in this assessment, the special needs for substitute natural gas will require pursuit of the development of this technology.

The results of the predicted ambient air quality calculations demonstrate the importance of small sources. Those energy technologies which are applicable to small and intermediate-size sources include: coal cleaning, resid desulfurization, coal refining, coal gasification, and fluidized-bed combustion of coal. The widespread application of coal cleaning, while not a total solution, could provide a significant reduction in SO_2 emissions particularly if chemical cleaning processes capable of removing all or part of the organic sulfur can be developed. It appears that smaller boilers can be modified to burn refined coal products. Development of coal refining technology will therefore make a clean fuel available for the small source sectors. Low Btu coal gasification systems are being developed for utility plant application. However, smaller scale systems, such as the Lurgi which is inherently a small unit, may be usefully applied for on-site generation of low Btu gas for certain industrial applications. High Btu gas from coal could serve as a clean fuel for small industrial sources if they can accommodate the expected higher cost. Development of designs for the fluidized-bed combustion of coal in boilers of intermediate size will provide some of the required emission control.

OPTIMUM TECHNOLOGY UTILIZATION

The fuel utilization matrix constructed for Scenario 1, Tables 5, 6, and 7, show that in 1975 and 1980 there will be a deficit in clean fuels and energy technology so that, according to this forecast, some dirty fuels will have to be burned in those years. On the surface, the outlook appears brighter for the years 1985 and 2000, since no uncontrolled combustion is forecast for those years. This results, however, from the optimistic preliminary projections of the availability of energy technology given in Table 4. It must also be emphasized that the basic fuel supply forecasts of Dupree and West,(1) which form the bases for Tables 5, 6, and 7, include substantial amounts of imported petroleum (36.9 percent and 70.3 percent of the total petroleum supply in 1975 and 2000, respectively) and gaseous fuel (10.2 percent and 28.2 percent of the total gaseous fuel supply in 1975 and 2000, respectively). It should be a national goal to minimize dependence on these foreign supplies to the greatest extent possible. Therefore, it is necessary to continue to accelerate the development and use of appropriate energy technologies not only to eliminate the need for uncontrolled combustion of dirty fuel but also to maximize the use of domestic fuel, principally coal. It is clear that to achieve both of these goals, it will be necessary to provide the required energy technologies at an even greater rate than is optimistically projected in Table 4.

The results of the technology assessment indicate that the following actions should be incorporated into the strategy for technology development and utilization:

- Stack-gas cleaning is the most advanced technology which will permit extensive use of domestic high sulfur coal over the near term with adequate emission control. Relative cost comparisons with alternate options suggest that only fluidized-bed combustion and chemical coal cleaning are competitive on a cost basis. The current low level of research and development in the latter areas makes it unlikely that stack gas cleaning will be displaced prior to 2000. Therefore, the remaining engineering problems associated with these technologies should be resolved as rapidly as possible, and implementation of the technology should be promoted to the fullest.

- Physical coal cleaning technology is available now, it is relatively inexpensive, and it can achieve on the average a 30 percent reduction in the sulfur dioxide emissions from combustion of the coal. Implementation of this technology should be extended fully.
- High-pressure fluidized-bed combustion of coal with advanced-cycle power generation has good potential for the extensive utilization of domestic coal. The development and implementation of this technology also should be stressed.
- The chemically active fluidized-bed combustion of oil exhibits the minimum residual emissions of those considered. The potential of this technology over the near term could be greater than indicated in the technology assessment if a major national program were undertaken. The low cost and high efficiency of the process in addition to the low emissions warrant such an emphasis.
- Chemical coal cleaning has potential for more efficient sulfur removal than does physical cleaning. The development of this technology will thus increase the quantity of coal which can be cleaned to 1 percent sulfur or less. In this regard, the two coal cleaning processes are not a duplication of effort. The less expensive physical process can be usefully applied to coals having sulfur contents in the range amenable to physical cleaning and chemical cleaning applied to coals with higher sulfur content. Accelerated development

and early implementation of this technology will further expand the nation's ability to utilize domestic coal.

- Continued development of the coal conversion technologies is warranted on the basis of special considerations as in the case of high Btu gasification as discussed previously.

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APPENDIX A

DATA TABLES FOR SELECTED MODULES

The unit emissions data derived for each of the modules are given in the following tables. The source of original data and the assumptions made are given in footnotes to each table, so that the calculations can be repeated. The references cited are listed at the end of this Appendix.

Table 34. ENVIRONMENTAL DATA FOR MODULE

Module - Gas Well
Unit - 10^6 Btu

Environmental Parameters	Fuel Input, Natural Gas
Air	
NO_x, lb	0.23(1)
SO_2, lb	0
CO, lb	0
Particulate, lb	0
Total organic material, lb	0.1(2)
Heat, 10^6 Btu	0
Water	
Suspended solids, lb	0
Dissolved solids, lb	0
Total organic material, lb	0
Heat, 10^6 Btu	0
Acid (H_2SO_4), lb	0
Solid	
Slag, lb	0
Ash, lb	0
Sludge, lb	0
Tailings, lb	0
Hazardous, lb	0
By-Products	12.6(3)
Occupational Health	
Deaths	2.2×10^{-9}(4)
Total Injuries	2.1×10^{-7}(5)
Man Days Lost	3.5×10^{-5}(6)
Land Use, acre-hr/10^6 Btu	0.06(7)
Approx. Module Efficiency	96%(8)

Footnotes for Table 34:

(1) a. Natural gas consumed to maintain pumping power in gas well(A-15) = 0.032 ft^3/ft^3 recovered.
b. NO_x emission factor(A-1) = 7.3×10^{-3} lb/ft^3 consumed.
c. Heating value of natural gas (assumed) = 1000 Btu/ft^3.

(2) a. Natural gas loss in gas well operation(A-15) = 0.0022 ft^3/ft^3 recovered.
b. Density of natural gas = 0.045 lb/ft^3.

(3) a. Hydrocarbon recovered (liquid phase)(A-15) = 0.047 ft^3 (equivalent gas volume)/ft^3 recovered.
b. The hydrocarbon is assumed as heptane (Molecular weight = 96).

(4) a. Total number of fatal injuries in oil and gas production(A-17, A-19) = 95.
b. Total energy from oil and gas production(A-17, A-18) = 43×10^{15} Btu.

(5) a. Total number of nonfatal injury in oil and gas production in 1969(A-17, A-19) = 9023.

(6) a. Total man-days lost in oil and gas production in 1969(A-17, A-19) = 1.49×10^6 man-days.

(7) a. Land requirement for gas well is assumed to be the same as that for oil well.

b. Land use for oil well (see Table A-5) = 0.06 acre-hour/10^6 Btu

(8) a. Efficient (assumed) = 96%.

TABLE 35. ENVIRONMENTAL DATA FOR MODULE

Module - Removal of Sulfur from Natural Gas
Unit - 10^6 Btu (output)

Environmental Parameters	Fuel Input, Natural Gas
Air	
NO_x, lb	Nil
SO_2, lb	0.025(1)
CO, lb	Nil
Particulate, lb	Nil
Total organic material, lb	Nil
Heat, 10^6 Btu	Nil
Water	
Suspended solids, lb	Nil
Dissolved solids, lb	Nil
Total organic material, lb	Nil
Heat, 10^6 Btu	Nil
Acid (H_2SO_4), lb	0
Solid	
Slag, lb	Nil
Ash, lb	Nil
Sludge, lb	Nil
Tailings, lb	Nil
Hazardous, lb	Nil
By-Products	0.24(2)
Occupational Health	Not determined
Deaths	Not determined
Total Injuries	Not determined
Man Days Lost	Not determined
Land Use, acre-hr/10^6 Btu	0.005(3)
Approx. Module Efficiency	100%(4)

Footnotes for Table 35:

(1) a. Table K-2 (in Reference A-26) gives the following 1970 data from 6 states:
SO_2 in Claus plants tail gas at 90% eff. = 441 T/D
SO_2 purged from plants not recovering sulfur = 2,335 T/D
Total gas production = 26.76×10^9 ft^3/d.
b. Assume 95% efficiency for Claus plants applied to all sour gas treatment plants, then:

$$\frac{(441/0.1 + 2335) \text{ ton } SO_2/\text{day} \times .05 \times 2000 \text{ lb/ton}}{26.76 \times 10^9 \text{ ft}^3/\text{day} \times 10^3 \text{ Btu/ft}^3} = 0.025 \frac{\text{lb } SO_2}{10^6 \text{ Btu}}$$

(2) a. at 95% efficiency for the Claus plants, the amount of SO_2 converted to sulfur is 19 times the amount of SO_2 emitted. Therefore, the amount of by-product sulfur produced is:

$$.025 \text{ lb } SO_2 \text{ emitted} \times 19 \times \frac{32 \text{ lb S}}{64 \text{ lb } SO_2} = 0.24 \text{ lb S}$$

(3) a. Land requirement for a 100 million ft^3/day plant (assumed) = 20 acres.

(4) a. Energy requirements for desulfurization process were not determined.

Table 36. ENVIRONMENTAL DATA FOR MODULE

Module -- Gas Pipeline
Unit -- 10^6 Btu

Environmental Parameters	Fuel Input, Natural Gas
Air	
NO_x, lb	0.304(1)
SO_2, lb	0
CO, lb	0
Particulate, lb	0
Total organic material, lb	0
Heat, 10^6 Btu	0
Water	
Suspended solids, lb	0
Dissolved solids, lb	0
Total organic material, lb	0
Heat, 10^6 Btu	0
Acid (H_2SO_4), lb	0
Solid	
Slag, lb	0
Ash, lb	0
Sludge, lb	0
Tailings, lb	0
Hazardous, lb	0
By-Products	
Occupational Health	
Deaths	Not determined
Total Injuries	Not determined
Man Days Lost	Not determined
Land Use, acre-hr/10^6 Btu	1.0(2)
Approx. Module Efficiency	95.9%(3)

Footnotes for Table 36:

(1) a. Natural gas consumed to maintain a compressor at 750 psia$^{(A-15)}$ = 0.042 ft^3/ft^3 transmitted.
b. NO$_x$ emission factor for running gas engines$^{(A-1)}$ = 7300 lb/10^6 ft^3 burned.

(2) a. Land requirement for pipelines to run a 1000 MW Power Plant (A-12) = 213 acres.

(3) a. Efficiency (assumed) = 95.9%.

TABLE 37. ENVIRONMENTAL IMPACTS OF MODULE

Module--Space Heating(1)
Unit--10^6 Btu (Input)

Environmental Impacts	Nat. Gas
Air	
NO_x, lb	0.081
SO_2, lb	0.001
CO, lb	0.015
Particulate, lb	0.005
Total organic material, lb	0.004
Water	
Suspended solids, lb	0
Dissolved solids, lb	0
Total organic material, lb	0
Solid	
Ash, lb	0
Sludge, lb	0
Approx. Module Efficiency	70%

Footnotes for Table 37:

(1) a. Values taken from Table A-46 in reference (A-26) were corrected to input basis.

TABLE 38. ENVIRONMENTAL DATA FOR MODULE

Module -- Oil/Gas Well, Onshore
Unit -- 10^6 Btu (output)

Environmental Parameters	Fuel Input, Crude Oil
Air	
NO_x, lb	8×10^{-6}(1)
SO_2, lb	6×10^{-5}(2)
CO, lb	3×10^{-8}(3)
Particulate, lb	3×10^{-6}(4)
Total organic material, lb	4×10^{-7}(5)
Heat, 10^6 Btu	0
Water	
Suspended solids, lb	0
Dissolved solids, lb	6.2(6)
Total organic material, lb	0.008(7)
Heat, 10^6 Btu	0
Acid (H_2SO_4), lb	0
Solid	
Slag, lb	0
Ash, lb	0
Sludge, lb	0
Tailings, lb	0
Hazardous, lb	0
By-Products	
Occupational Health	
Deaths	2.2×10^{-9}(8)
Total Injuries	2.1×10^{-7}(9)
Man Days Lost	3.5×10^{-5}(10)
Land Use, acre-hr/10^6 Btu	0.06(11)
Approx. Module Efficiency	100%

Footnotes for Table 38:

(1) a. Amount of oil that becomes air pollutants per barrel of oil produced (assumed) = 2×10^{-5} barrels.
b. Heating value of oil (assumed) = 6.3×10^6 Btu/bbl.
c. NO_x emission factor(A-1) = 60 lb/10^3 gal.
d. Oil is assumed to be the same as industrial residual oil.

(2) a. SO_2 emission factor(A-1) = 157S lb/10^3 gal.
b. Sulfur content of oil, S (assumed) = 2.88%.

(3) a. CO emission factor(A-1) = 0.2 lb/10^3 gal.

(4) a. Particulate emission factor(A-1) = 23 lb/10^3 gal.

(5) a. Hydrocarbon emission factor(A-1) = 3 lb/10^3 gal.

(6) a. Dissolved solid emission comes from saltwater brine.
b. Total brine production(A-16) = 25 million bbls/day.
c. Total on shore oil production rate(A-17) = 3.3×10^9 bbls/year.
d. 4% of brine goes to streams (assumed).
e. There are 100 lb of dissolved solids per barrel of oil (assumed).

(7) a. The brine is cleaned to remove all but 50 ppm oil (assumed).

(8) a. Total number of fatal injury in oil and gas production in 1969(A-17, A-19) = 95.
b. Total energy from oil and gas production(A-17,A-18) = 43×10^{15} Btu.

(9) a. Total number of nonfatal injury in oil and gas production in 1969(A-17,A-19) = 9022.

(10) a. Total man-days lost(A-17,A-19) = 1.49×10^6 man-days.

(11) a. Land requirement for an oil well producing 6200 barrels of oil per year (assumed) = 1/4 acres.

(12) a. Efficiency of operation (assumed) = 100%.

TABLE 39. ENVIRONMENTAL DATA FOR MODULE

Module -- Oil Pipeline
Unit -- 10^6 Btu (output)

Environmental Parameters	Fuel Input, Crude Oil
Air	
NO_x, lb	0.009(1)
SO_2, lb	0.016(2)
CO, lb	2×10^{-5}(3)
Particulate, lb	0.002(4)
Total organic material, lb	0.0003(5)
Heat, 10^6 Btu	0.009(6)
Water	
Suspended solids, lb	0
Dissolved solids, lb	0
Total organic material, lb	0
Heat, 10^6 Btu	0
Acid (H_2SO_4), lb	0
Solid	
Slag, lb	0
Ash, lb	0
Sludge, lb	0
Tailings, lb	0
Hazardous, lb	0
By-Products	0
Occupational Health	
Deaths	9×10^{-10}(7)
Total Injuries	8×10^{-8}(8)
Man Days Lost	1.5×10^{-5}(9)
Land Use, acre-hr/10^6 Btu	0.3(10)
Approx. Module Efficiency	99.1(11)

Footnotes for Table 39:

(1) a. Fraction of crude oil transported by pipeline$^{(A-20)}$ = 77.4%.
b. Total crude oil transported in 1970$^{(A-20)}$ = 1.58×10^9 barrels.
c. Fraction of crude oil transported by diesel powered pump$^{(A-21)}$ = 16.3% of crude oil transported by pipeline.
d. Crude oil consumed to supply power for pumping$^{(A-22)}$ = 1.45×10^8 gal/year.
e. NO_x emission factor$^{(A-1)}$ = 80 lb/10^3 gal burned.
f. Heating value of crude oil (assumed) = 6.3×10^6 Btu/bbl.

(2) a. SO_2 emission factor$^{(A-1)}$ = 142 lb/10^3 gal burned.

(3) a. CO emission factor$^{(A-1)}$ = 0.2 lb/10^3 gal burned.

(4) a. Particulate emission factor$^{(A-1)}$ = 16 lb/10^3 gal burned.

(5) a. Hydrocarbon emission factor$^{(A-1)}$ = 3 lb/10^3 gal burned.

(6) a. Assumed efficiency of oil pipeline = 99.1%.

(7) a. Death rate in oil transportation by pipeline (assumed) = 0.08 deaths/10^6 man-hours.
b. Man-hours required to transport the amount of oil for running a 1000 MW Power Plant (assumed) = 7×10^5 man-hours.

(8) a. Injury rate in oil transportation by pipeline (assumed) = 7.22 injuries/10^6 man-hours.

(9) a. Man-days lost per death (assumed) = 6000 days/death.
b. Man-days lost per injury (assumed) = 125 days/injury.

(10) a. Land usage for pipeline$^{(A-12)}$ = 65 acres/year.
b. Period of land use (assumed) = 35 years.

(11) a. Efficiency of pipeline operation (assumed) = 99.1%.

TABLE 40. ENVIRONMENTAL DATA FOR MODULE

Module - Conventional Refinery, Domestic Crude
Unit - 10^6 Btu (output)

Environmental Parameters	Fuel Input, Domestic Crude(0.76% S)(1)
Air	
NO_x, lb	0.023(2)
SO_2, lb	0.12(3)
CO, lb	0.003(4)
Particulate, lb	0.002(5)
Total organic material, lb	0.025(6)
Heat, 10^6 Btu	0.10(7)
Water	
Suspended solids, lb	0.004(8)
Dissolved solids, lb	0.09(9)
Total organic material, lb	0.001(10)
Heat, 10^6 Btu	Negligible after cooling tower
Acid (H_2SO_4), lb	0.0004(11)
Solid	
Slag, lb	0
Ash, lb	0
Sludge (dry weight), lb	0.007(12)
Tailings, lb	0
Hazardous, lb	0
By-Products, lb	0.24(13)
Occupational Health	
Deaths	1.3×10^{-9}(14)
Total Injuries	9.6×10^{-8}(15)
Man Days Lost	2.3×10^{-5}(16)
Land Use, acre-hr/10^6 Btu	0.008(17)
Approx. Module Efficiency	90%(18)

Footnotes for Table 40:

(1) a. Sulfur content of input crude taken as 0.76%

(2) a. Average refinery energy consumption$^{(A-24)}$ = 70,400 Btu/bbl crude oil processed.
b. Assume all energy supplied by combustion of crude or refinery products
c. Heating value of crude oil (assumed) = 6.3 x 10^6 Btu/bbl.
d. NO_x emission from combustion operations (A-26) = 130 lb/10^3 bbl crude oil processed.

(3) a. Assume 0.75% S residual burned as refinery fuel.
b. SO_2 emission (A-26) = 695 lb/10^3 bbl crude oil processed
c. 95% removal, no Claus plant tail gas treatment.

(4) a. CO emission from catalytic cracking catalyst regenerator (A-26) = 15 lb/10^3 bbl crude oil processed.

(5) a. Particulate emission from catalytic cracking (A-26) = 12 lb/10^3 bbl crude oil processed (after controlled by cyclones).

(6) a. Hydrocarbon emission (A-26) = 140 lb/10^3 bbl crude oil processed.

(7) a. Refinery energy consumption$^{(A-24)}$ = 704,000 Btu/bbl of crude oil processed.
b. Heating value of crude oil (assumed) = 6.3 x 10^6 Btu/bbl.

(8) a. Suspended solids emission (assumed) = 20 lb/10^3 bbl processed.

(9) a. Dissolved solids emission (assumed) = 500 lb/10^3 bbl processed.

(10) a. Total organic material emission (assumed) = 8 lb/10^3 bbl processed.

(11) a. Phenol emission (assumed) = 2 lb/10^3 bbl processed.

(12) a. Average sludge production rate$^{(A-25)}$ = 0.08 $yd^3/10^3$ bbl processed.
b. Density of sludge (assumed) = 60 lb/ft^3.
c. Solid content of sludge (assumed) = 30%.

(13) a. Assume an average of 0.2% sulfur in the products.
b. Density of crude oil (assumed) = 7.29 lb/gal.

(14) a. Deaths attributed to the operation of a refinery supplying fuel to a 1000 MW power plant$^{(A-12)}$ = 0.09 deaths.

(15) a. Injuries attributed to the operation of a refinery supplying fuel to a 1000 MW power plant$^{(A-12)}$ = 6.4 injuries.

(16) a. Total work days lost attributed to the operation of a refinery supplying fuel to a 1000 MW power plant$^{(A-12)}$ = 1,530 man-days.

(17) a. Minimum land requirement for refinery processing units (assumed) = 2 acres/1000 bbl/day.

(18) a. Energy required to operate plant$^{(A-24)}$ = 704,000 Btu/bbl crude oil processed.

TABLE 41. ENVIRONMENTAL IMPACTS OF MODULE

Module-- Space Heating(1)
Unit--10^6 Btu (Input)

Environmental Impacts	Dist. Oil
Air	
NO_x, lb	0.135
SO_2, lb	0.263
CO, lb	0.030
Particulate, lb	0.017
Total organic material, lb	0.004
Water	
Suspended solids, lb	0
Dissolved solids, lb	0
Total organic material, lb	0
Solid	
Ash, lb	0
Sludge, lb	0
Approx. Module Efficiency	70%

Footnotes for Table 41:

(1) a. Values taken from Table A-46 in reference (A-26) were corrected to input basis.

TABLE 42. ENVIRONMENTAL DATA FOR MODULE

Module - Crude Oil Gasification
Unit - 10^6 Btu (output)

Environmental Parameters	Fuel Input, Crude Oil
Air	
NO_x, lb	0.08(1)
SO_2, lb	0.03-0.05(2)
CO, lb	Negligible
Particulate, lb	0.002(3)
Total organic material, lb	0.004(4)
Heat, 10^6 Btu	0.3(5)
Water	
Suspended solids, lb	--
Dissolved solids, lb	0.02(6)
Total organic material, lb	Negligible
Heat, 10^6 Btu	Negligible after cooling tower
Acid (H_2SO_4), lb	--
Solid	
Slag, lb	--
Ash, lb	0.06-0.12(7)
Sludge, lb	0.06-0.12(8)
Tailings, lb	--
Hazardous, lb	--
By-Products	1.3-2.5(9)
Occupational Health	
Deaths	Not determined
Total Injuries	Not determined
Man Days Lost	Not determined
Land Use, acre-hr/10^6 Btu	0.03-0.05(10)
Approx. Module Efficiency	77%(11)

Footnotes for Table 42:

(1) a. Plant efficiency of crude oil SNG plant (assumed) = 77%.
b. 23% of input is consumed as liquid fuel for plant operation (assumed).
c. NO_x emission factor$^{(A-1)}$ = 40 lb/10^3 gal.
d. Heating value of input crude = 6.3 x 10^6 Btu/barrel (assumed).

(2) a. Sulfur content of crude oil (assumed) = 2 to 4%.
b. Sulfur removal efficiency of Claus plant and tail gas treatment (assumed) = 99%.
c. Density of crude oil - 7.3 lb/gal.

(3) a. Particulate emission factor for fluid catalytic cracking unit$^{(A-1)}$ = 61 lb/10^3 bbl fresh feed.
b. Fraction of fresh feed to be cracked in this process (assumed) = 1/3.
c. Particulate removal efficiency of cyclone (assumed) = 50%.

(4) a. Losses of crude oil to atmosphere (assumed) = 20 lb/10^3 bbl input.

(5) a. 23% of input fuel is consumed for plant operation (assumed).

(6) a. Salt content of crude oil (assumed) = 100 lb/10^3 bbl.

(7) a. Solid waste from spent catalyst not worth reclaiming (assumed) = 300 to 600 lb/10^3 bbl.

(8) a. Sludges from water treatment (assumed) = 300 to 600 lb/10^3 bbl.

(9) a. By-product is sulfur. Quantity derived from assumed sulfur content of input crude (2 to 4%) and 99% recovery in Claus unit and tail-gas treatment.

(10) a. Land required for a 100,000 bbl/day plant (assumed) = 600 to 1000 acres.

(11) a. Efficiency of plant (assumed) = 77%.

TABLE 43. **ENVIRONMENTAL DATA FOR MODULE**

Module - Strip-mined coal, West
Unit - 10^6 Btu (output)

Environmental Parameters	With Land Restoration and Treatment of Acid Drainage(1)
Air	
NO_x, lb	0.00008 (Bulldozer operation)(2)
SO_2, lb	Negligible
CO, lb	Negligible
Particulate, lb	0.07(3)
Total organic material, lb	Negligible
Heat, 10^6 Btu	Negligible
Water	
Suspended solids, lb	0.28(4)
Dissolved solids, lb	Not determined
Total organic material, lb	Negligible
Heat, 10^6 Btu	Negligible
Acid (H_2SO_4), lb	Nil
Solid	
Slag, lb	0
Ash, lb	0
Sludge, lb	0
Tailings, lb	0
Hazardous, lb	0
By-Products	None
Occupational Health	
Deaths	6.5×10^{-9}(5)
Total Injuries	3.1×10^{-7}(6)
Man Days Lost	9.6×10^{-5}(7)
Land Use, acre-hr/10^6 Btu	0.16(8)
Approx. Module Efficiency	99.8%

Footnotes for Table 43:

(1) a. Impacts will be negligible after land restorations. Stated impacts will occur during the actual operation.

(2) a. NO_x comes from a disel powered bulldozer used for reclamation.
b. Time requirement for reclamation (assumed = 4 hr/acre.
c. Bulldozer engine power (assumed) = 150 hp.
d. Fuel consumption rate$^{(A-1)}$ = 0.5 lb/hp - hr.
e. NO_x emission factor$^{(A-1)}$ = 0.37 lb/gal fuel used.
f. Average thickness of coal seam (assumed = 5 ft.
g. Coal bulk density (assumed) = 82 lb/ft^3.
h. Heating value of western coal (assumed) = 9235 Btu/lb.

(3) a. Emission factor (given for suspended particulate from primary rock crushing and for mining of copper ore) = 0.1 lb/ton of overburden.
b. Average overburden per ton of coal = 13 tons.

(4) a. Rate of silt run-off (assumed) = 5000 tons/mi^2-year.
b. Average thickness of coal seam (assumed) = 5 ft.
c. Coal bulk density (assumed) = 82 lb/ft^3.
d. Reclamation period (private communication, EPA) = 3 years.

(5) a. Death rate for strip coal mining$^{(A-12)}$ = 0.12/10^6 ton coal.
b. Heating value of coal (assumed) = 18.47 x 10^6 Btu/ton of coal.

(6) a. Injury rate for strip coal mining$^{(A-12)}$ = 5.65 injuries/10^6 ton coal.

(7) a. Man-days lost per death (assumed) = 6000 days/death.
b. Man-days lost per injury (assumed) = 182.6 days/injury.

(8) a. Land required for 10^6 tons of coal$^{(A-12)}$ = 112 acres.
b. Time requirement for reclamation (assumed) = 3 years.

(9) a. Efficiency of strip mine operation (assumed) = 99.8%.

TABLE 44. ENVIRONMENTAL DATA FOR MODULE

Module - Railroad Transportation of Coal
Unit - 10^6 Btu (output)

Environmental Parameters	Fuel Input, Coal
Air	
NO_x, lb	0.02(1)
SO_2, lb	0.0014(2)
CO, lb	0.015(3)
Particulate, lb	0.0015(4)
Total organic material, lb	Negligible
Heat, 10^6 Btu	0.0039(5)
Water	
Suspended solids, lb	Negligible
Dissolved solids, lb	Negligible
Total organic material, lb	Negligible
Heat, 10^6 Btu	Negligible
Acid (H_2SO_4), lb	Negligible
Solid	
Slag, lb	Negligible
Ash, lb	Negligible
Sludge, lb	Negligible
Tailings, lb	0.083(6)
Hazardous, lb	Negligible
By-Products	Negligible
Occupational Health	
Deaths	3.2×10^{-8}(7)
Total Injuries	3.2×10^{-7}(8)
Man Days Lost	2.2×10^{-4}(9)
Land Use, acre-hr/10^6 Btu	0.29(10)
Approx. Module Efficiency	100%(11)

Footnotes for Table 44:

(1) a. Total quantity of coal transported$^{(A-7)}$ = 695 x 10^6 tons/year.
b. Total shipment from rail and barge$^{(A-8)}$ = 8.13%.
c. Total shipment from rail (assumed) = 7.13%.
d. NO_x emission per 10^6 hp-hr$^{(A-9)}$ = 15.43 tons/10^6 hp-hr.
e. Assume a 3,000 horsepower required for each 2,000 tons of gross load in a locomotive-train system.
f. Average horsepower of the locomotive-train system$^{(A-10)}$ = 74.9% of the maximum horsepower.
g. Ratio of average gross tonnate to average net tonnage$^{(A-10)}$ = 2.3481.

(2) a. SO_2 emission per 10^6 hp-hr$^{(A-9)}$ = 1.1 tons/10^6 hp-hr.

(3) a. CO emission per 10^6 hp-hr$^{(A-9)}$ = 11.9 tons/10^6 hp-hr.

(4) a. Particulate emission (assumed) = 10% of CO.

(5) a. Hp-hr required to move the ton-mill of coal transported by rail per year = 7554.6 x 10^6 hp-hr/yr.
b. Definition and value of the brake thermal efficiency$^{(A-11)}$=

$$\frac{\text{Fuel flow/Brake fuel consumption}}{\text{[Fuel flow] Fuel heating value}} = \frac{(100/(0.456)}{(19{,}156)(3.929 \times 10^{-4})} = 29.1\%.$$

c. Energy that the fuel carries into the locomotive = 2.59 x 10^{10} hp-hr/year.

(6) a. The fraction of intransit storage-handling dust loss = 0.1% of the total coal transported.

(7) a. Number of death occurred on the railroad system$^{(A-10)}$ = 2299 death/year.
b. Total ton-miles shipped by rail$^{(A-8)}$ = 7.7 x 10^{11} tons/year.
c. Ton-miles shipped for coal by rail$^{(A-8)}$ = 1.26 x 10^{11}/year.

(8) a. Number of injuries occurred on the railroad system$^{(A-10)}$ = 23356 injuries/year.

(9) a. Man days lost per death (assumed) = 6000 man days.
b. Man days lost per injury (assumed) = 100 man days.

(10) a. Current land rights of the railroad system$^{(A-10)}$ = 3760 sq miles.

(11) a. Module efficiency (assumed) = 100%.

TABLE 45. ENVIRONMENTAL IMPACTS OF MODULE

Module--Space Heating(1)
Unit--10^6 Btu (Input)

Environmental Impacts	Coal (1%)
Air	
NO_x, lb	0.117
SO_2, lb	1.47(2)
CO, lb	3.49
Particulate, lb	0.775
Total organic material, lb	0.775
Water	
Suspended solids, lb	0
Dissolved solids, lb	0
Total organic material, lb	0
Solid	
Ash, lb	6.9(3)
Sludge, lb	0
Approx. Module Efficiency	50%

Footnotes for Table 45:

(1) a. Values taken from Table A-46 in reference (A-26) were corrected to input basis.

(2) a. Sulfur content of coal is assumed to be 1%.

(3) a. Ash content of coal is assumed to be 10%.

b. Heating value of coal = 13,000 Btu/lb coal.

c. Ash emission as particulate = 0.78 lb/10^6 Btu.

TABLE 46. ENVIRONMENTAL DATA FOR MODULE

Module - Hygas (Gasification of Coal-High Btu)
Unit - 10^6 Btu (output)

Environmental Parameters	Fuel Input, Coal, East
Air	
NO_x, lb	0.25(1)
SO_2, lb	0.55(2)
CO, lb	0
Particulate, lb	0.12(3)
Total organic material, lb	0.0014(4)
Heat, 10^6 Btu	0.34(5)
Water	
Suspended solids, lb	0
Dissolved solids, lb	0
Total organic material, lb	Negligible
Heat, 10^6 Btu	Negligible after cooling tower
Phenols, lb	4.6×10^{-5}(6)
Solid	
Slag, lb	0
Ash, lb	6.7(7)
Sludge, lb	25.8(8)
Tailings, lb	0
Hazardous, lb	0
By-Products	2.0(9)
Occupational Health	
Deaths	5×10^{-9}(10)
Total Injuries	1.7×10^{-7}(10)
Man Days Lost	4.6×10^{-5}(11)
Land Use, acre-hr/10^6 Btu	0.02(12)
Approx. Module Efficiency	66%(13)

Footnotes for Table 46:

(1) a. NO_x emission comes from a 110 MW power plant in the Hygas plant.
b. NO_x emission factor (assumed) = 0.72 lb/10^6 Btu generated by the power plant.
c. Hygas plant capacity$^{(A-6)}$ = 80 x 10^6 scfd.
d. Heating value of gas produced$^{(A-6)}$ = 950 Btu/ft^3.

(2) a. SO_2 emission comes from two limestone scrubbers.
b. Sulfur from limestone scrubbers$^{(A-6)}$ = 1300 lb/hr.
c. Sulfur content of coal used in this calculation (assumed)=3%.
d. Adjustment factor for sulfur content$^{(A-6)}$ = 0.68.

(3) a. Ash content of coal used in this calculation (assumed) = 14.4%.
b. Adjustment factor for ash content$^{(A-6)}$ = 1.31.
c. 65% of total ash goes to scrubber as particulate (assumed).
d. Limestone scrubber efficiency for removal of particulate (assumed) = 99%.

(4) a. Hydrocarbon emission comes from a 110 MW power plant.
b. Hydrocarbon emission factor (assumed) = 0.04 lb/10^6 Btu.

(5) a. Efficiency of Hygas plant$^{(A-6)}$ = 66%.

(6) a. Assumed to be same as for CO_2 acceptor (see CO_2 Acceptor for the detail).

(7) a. Ash comes from boiler (bottom ash).

(8) a. Sulfur from limestone scrubbers$^{(A-6)}$ = 7600 lb/hr.
b. Sulfur content of sludge = 12%.
c. Adjustment factor for sulfur content in fuel$^{(A-6)}$ = 0.68.
d. Sludge comes from limestone scrubbers (limestone slurry plus particulate collected).

(9) a. Elemental sulfur from Claus plant is the sole by-product (assumed).
b. Adjustment factor for sulfur content in coal = 0.68.

(10) a. Man-hours required for a $1x10^{10}$ Btu/hr capacity Hygas plant (assumed) = 4000 man hours/day.
b. Injury rate (assumed) = 10 injuries/10^6 man hours.
c. 3% of injury assumed fatal.

(11) a. Man-days lost per death (assumed) = 6000 days/death.
b. Man-days lost per injury (assumed) = 95 days/injury.

(12) a. Personal communication with EPA.

(13) a. Reported by Processes Research.$^{(A-6)}$

TABLE 47. ENVIRONMENTAL DATA FOR MODULE

Module -- Conventional Boiler
Unit -- 10^6 Btu (input)

Environmental Parameters	Fuel Input, Natural Gas
Air	
NO_x, lb	0.39(1)
SO_2, lb	0.0006(2)
CO, lb	0.0004(3)
Particulate, lb	0.015(4)
Total organic material, lb	0.04(5)
Heat, 10^6 Btu	0.63(6)
Water	
Suspended solids, lb	0.016(7)
Dissolved solids, lb	0
Total organic material, lb	0
Heat, 10^6 Btu	Negligible after cooling tower
Acid (H_2SO_4), lb	0
Solid	
Slag, lb	0
Ash, lb	0
Sludge, lb	0
Tailings, lb	0
Hazardous, lb	0
By-Products	0
Occupational Health	
Deaths	1.5×10^{-10}(8)
Total Injuries	8.9×10^{-9}(9)
Man Days Lost	2.9×10^{-6}(10)
Land Use, acre-hr/10^6 Btu	0.02(11)
Approx. Module Efficiency	37%(12)

Footnotes for Table 47:

(1) a. NO_x emission factor$^{(A-1)}$ = 39 lb/10^6 ft^3 of natural gas.
b. Heating value of natural gas (assumed) = 1000 Btu/ft^3.

(2) a. SO_2 emission factor for burning natural gas = 0.6 lb/10^6 ft^3.

(3) a. CO emission factor for burning natural gas = [illegible].4 lb/10^6 ft^3.

(4) a. Particulate emission factor for burning natural gas = 15 lb/10^6 ft^3.

(5) a. Hydrocarbon emission factor for burning natural gas = 40 lb/10^6 ft^3.

(6) a. Efficiency of gas fired conventional boiler = 37%.

(7) a. Suspended solid emission from a 1000 MW gas fired Power Plant (A-12) = 548 tons.

(8) a. Deaths attributed to a 1000 MW gas fired Power Plant$^{(A-12)}$ = 0.01 death/year.

(9) a. Injuries attributed to a 1000 MW gas fired Power Plant$^{(A-12)}$ = 0.6 injuries/year.

(10) a. Man-days lost attributed to a 1000 MW gas fired Power Plant$^{(A-12)}$ = 197 man-days/year.

(11) a. Land requirement for a 1000 MW gas fired Power Plant$^{(A-12)}$ = 150 acres.

(12) a. Efficiency of gas fired Power Plant (assumed) = 37%.

TABLE 48. ENVIRONMENTAL IMPACTS OF MODULE

Module--Conventional Boiler
Unit--10^6 Btu (Input)

Environmental Impacts	Dist. Fuel Oil (0.3% S)
Air	
NO_x, lb	0.75 (1)
SO_2, lb	0.336 (2)
CO, lb	0.0003 (3)
Particulate, lb	0.057 (4)
Total organic material, lb	0.014 (5)
Water	
Suspended solids, lb	0
Dissolved solids, lb	0
Total organic material, lb	0
Solid	
Ash, lb	0
Sludge, lb	0
Approx. Module Efficiency	37% (6)

Footnotes for Table 48:

(1) a. Heating value of distillate fuel oil$^{(A-1)}$ = 140,000 Btu/gal.
    b. NO_x emission factor$^{(A-1)}$ = 105 lb/1000 gal.

(2) a. Sulfur content of distillate fuel oil, S (assumed) = 0.3%.
    b. SO_2 emission factor$^{(A-1)}$ = 157 S lb/1000 gal.

(3) a. CO emission factor$^{(A-1)}$ = 0.04 lb/1000 gal.

(4) a. Particulate emission factor$^{(A-1)}$ = 8 lb/1000 gal.

(5) a. Hydrocarbon emission factor$^{(A-1)}$ = 2 lb/1000 gal.

(6) a. Plant efficiency was assumed to be 37%.

TABLE 49. ENVIRONMENTAL DATA FOR MODULE

Module -- Oil Barge
Unit -- 10^6 Btu (Output)

Environmental Parameters	Fuel Input, Residual Oil
Air	
NO_x, lb	0.0013(1)
SO_2, lb	0.0014(2)
CO, lb	0.0011(3)
Particulate, lb	0.0018(4)
Total organic material, lb	0.0008(5)
Heat, 10^6 Btu	0.004(6)
Water	
Suspended solids, lb	nil
Dissolved solids, lb	nil
Total organic material, lb	0.015(7)
Heat, 10^6 Btu	nil
Acid (H_2SO_4), lb	nil
Solid	
Slag, lb	nil
Ash, lb	nil
Sludge, lb	nil
Tailings, lb	nil
Hazardous, lb	nil
By-Products	nil
Occupational Health	
Deaths	9×10^{-10}(8)
Total Injuries	8×10^{-8}(9)
Man Days Lost	1.5×10^{-5}(10)
Land Use, acre-hr/10^6 Btu	0(11)
Approx. Module Efficiency	99.6%(12)

Footnotes for Table 49:

(1) a. Assume 20,000 tons per shipment.
b. NO_x emission factor for motor ship$^{(A-1)}$ = 1.4 lb/mi.
c. Trip distance per shipment (assumed) = 325 miles.

(2) a. SO_2 emission factor for motor ship$^{(A-1)}$ = 1.5 lb/mi for 0.5% sulfur content for fuel.

(3) a. CO emission factor for motor ship$^{(A-1)}$ = 1.2 lb/mi.

(4) a. Particulate emission factor for motor ship$^{(A-1)}$ = 2lb/mi.

(5) a. Hydrocarbon emission factor for motor ship$^{(A-1)}$ = 0.9 lb/mi.

(6) a. Total heat required per 10^6 Btu transported (assumed) = 3800 Btu.

(7) a. Total oil discharge in oil transport and in tank cleaning operations$^{(A-12)}$ = 0.27% of shipment.

(8) a. Death rate in oil transportation by barge$^{(A-12)}$ (assume that barge operation is similar to tanker operation) = 0.08 deaths/10^6 man-hours.
b. Man-hour required to transport the amount of crude oil to operate a 1000 MW Power Plant$^{(A-12)}$ = 7 x 10^5 man-hours.

(9) a. Injury rate in oil transportation by barge$^{(A-12)}$ (assume that barge operation is similar to tanker operation) = 7.22 injuries/10^6 man-hours.

(10) a. Man-days lost per death (assumed) = 6000 days/death.
b. Man-days lost per injury (assumed) = 125 days/injury.

(11) a. Land requirement for port facilities not estimated.

(12) a. Energy consumption rate per 10^6 Btu of crude oil transported (assumed) = 3800 Btu.

TABLE 50. ENVIRONMENTAL IMPACTS OF MODULE

Module--Conventional Boiler(1)
Unit--10^6 Btu (Input)

Environmental Impacts	1% S Resid
Air	
NO_x, lb	.7
SO_2, lb	1.04
CO, lb	0
Particulate, lb	0.05
Total organic material, lb	0.01
Water	
Suspended solids, lb	0
Dissolved solids, lb	0
Total organic material, lb	0
Solid	
Ash, lb	0
Sludge, lb	0
Approx. Module Efficiency	37%

Footnotes for Table 50:

(1) a. Values were taken from Table A-43 in reference (A-26). SO_2 emission was corrected to 1% sulfur resid.

TABLE 51. ENVIRONMENTAL DATA FOR MODULE

Module -- Oil Tanker
Unit -- 10^6 Btu (Output)

Environmental Parameters	Fuel Input, Crude Oil
Air	
NO_x, lb	0.0015(1)
SO_2, lb	0.0016(2)
CO, lb	0.0013(3)
Particulate, lb	0.0021(4)
Total organic material, lb	9×10^{-5}(5)
Heat, 10^6 Btu	0.005(6)
Water	
Suspended solids, lb	0
Dissolved solids, lb	0
Total organic material, lb	0.015(7)
Heat, 10^6 Btu	0
Acid (H_2SO_4), lb	0
Solid	
Slag, lb	0
Ash, lb	0
Sludge, lb	0
Tailings, lb	0
Hazardous, lb	0
By-Products	0
Occupational Health	
Deaths	9×10^{-10}(8)
Total Injuries	8×10^{-8}(9)
Man Days Lost	1.5×10^{-5}(10)
Land Use, acre-hr/10^6 Btu	0(11)
Approx. Module Efficiency	99.5(12)

Footnotes for Table 51:

(1) a. NO_x emission by oil tanker to transport crude oil for a 1000 MW Power Plant(A-12) = 51 tons/year.

(2) a. SO_2 emission by oil tanker to transport crude oil for a 1000 MW Power Plant (A-12) = 55 tons/year.

(3) a. CO emission by oil tanker to transport crude oil for a 1000 MW Power Plant(A-12) = 44 tons/year.

(4) a. Particulate emission by oil tanker to transport crude oil for a 1000 MW Power Plant(A-12) = 72 tons/year.

(5) a. Hydrocarbon emission by oil tanker to transport crude oil for a 1000 MW Power Plant(A-12) = 3 tons/year.

(6) a. Efficiency of oil tanker operation (assumed) = 99.5%.

(7) a. Total oil discharge in oil transport and in tank cleaning operations(A-12) = 0.027% of shipment.

(8) a. Death rate in oil transportation by tanker(A-12) = 0.08 deaths/10^6 man-hours.
b. Man-hours required to transport the amount of crude oil to
(9) operate a 1000 MW Power Plant(A-12) = 7 x 10^5 man-hours.

a. Injury rate in oil transportation by tanker(A-12) = 7.22 injuries/10^6 man-hours.

(10) a. Man-days lost per death (assumed) = 6000 days/death.
b. Man-days lost per injury (assumed) =125 days/injury.

(11) a. Land requirement for port facilities not estimated.

(12) a. Efficiency of oil tanker (assumed) = 99.5%.

TABLE 52. ENVIRONMENTAL DATA FOR MODULE

Module - Conventional Boiler (Coal)
Unit - 10^6 Btu (Input)

Environmental Parameters	Fuel Input, Coal, West
Air	
NO_x, lb	0.98(1)
SO_2, lb	1.65(2)
CO, lb	0.054(3)
Particulate, lb	0.07(4)
Total organic material, lb	0.016(5)
Heat, 10^6 Btu	0.63(6)
Water	
Suspended solids, lb	0.025(7)
Dissolved solids, lb	0
Total organic material, lb	0.011(8)
Heat, 10^6 Btu	Negligible after cooling tower
Acid (H_2SO_4), lb	0
Solid	
Slag, lb	0
Ash, lb	9.0(9)
Sludge, lb	0
Tailings, lb	0
Hazardous, lb	0
By-Products	0
Occupational Health	
Deaths	3.3×10^{-10}(10)
Total Injuries	1.4×10^{-8}(10)
Man Days Lost	5.1×10^{-6}(11)
Land Use, acre-hr/10^6 Btu	0.1(12)
Approx. Module Efficiency	37%(13)

Footnotes for Table 52:

(1) a. NO_x emission factor(A-1) = 18 lb/ton coal burned.
b. Heating value of western coal (assumed) 9200 Btu/lb.

(2) a. SO_2 emission factor(A-1) = 38 S lb/ton coal burned.
b. Sulfur content, S (assumed) = 0.8%.

(3) a. CO emission factor(A-1) = 1 lb/ton coal burned.

(4) a. Particulate emission factor(A-1) = 16A lb/ton coal burned.
b. Ash content, A (assumed) = 8.4%.
c. Electrostatic precipitator efficiency (assumed) = 99%.

(5) a. Hydrocarbons emission factor(A-1) = 0.3 lb/ton coal burned.

(6) a. Efficiency of conventional boiler (assumed) = 37%.

(7) a. Total solid to water(A-12) = 0.036 lb/10^6 Btu.
b. Fraction of suspended solid (assumed) = 70%.

(8) a. Fraction of organic material in total solid (assumed) = 30%.

(9) a. Ash content of coal (assumed) = 8.4%.

(10) a. Man-hour required per 10^6 Btu for conventional power plant(A-13) = 2.4×10^{-3} man hour.
b. Total injuries per 10^6 man-hour(A-13) = 5.7.
c. Death rate(A-12) = 2.4% of injuries.

(11) a. Days lost per death (assumed) = 6000 days/death.
b. Days lost per injury (assumed) = 229 days/death.

(12) a. Land required for a 1000 MW power plant (assumed) = 800 acres.

(13) a. Efficiency of conventional boiler (assumed) = 37%.

TABLE 53. ENVIRONMENTAL DATA FOR MODULE

Module--Physical Cleaning of Coal
Unit--10^6 Btu (output)

Environmental Parameters	With Environmental Control
Air	
NO_x, lb	0.006(1)
SO_2, lb	0.004(2)
CO, lb	--
Particulate, lb	0.01(3)
Total organic material, lb	--
Water	
Suspended solids, lb	Negligible
Dissolved solids, lb	Negligible
Total organic material, lb	Negligible
Acid (H_2SO_4), lb	Negligible
Solid	
Slag, lb	0
Ash, lb	0
Sludge, lb	0.3(4)
Tailings, lb	Negligible
Approx. Module Efficiency	88%(5)

Footnotes for Table 53:

(1) a. NO_x from thermal dryer. Operating characteristics for evaporating water from wet coal(A-2) = 550 tons of coal produced per 50 tons of water evaporated.

b. Heat required for water evaporation = 1000 Btu/lb water.

c. Heating value of coal = 12,000 Btu/lb of coal.

d. NO_x emission factor(A-1) = 18 lb/ton of coal burner.

e. No control equipment.

(2) a. SO_2 emission factor(A-1) = 38 S lb/ton coal burned.

b. Sulfur content of coal, S (assumed) = 3%.

c. Lime scrubber control efficiency (assumed) = 90%.

(3) a. Particulate emission factor for thermal dryer(A-1) = 25 lb/ton coal product.

b. Heating value of coal product = 13,180 Btu/lb.

c. Control efficiency of multiple cyclones with wet scrubber(A-1) 99.0% removal.

(4) a. Sludge comes from SO_2 and H_2SO_4 control (assumed).
b. Sulfur content of sludge (assumed) = 12%.

(5) a. The efficiency is assumed to be 88%.

TABLE 54. ENVIRONMENTAL DATA FOR MODULE

Module - CAFB Boiler (Residual Oil) + Combined Cycle
Unit - 10^6 Btu (input)

Environmental Parameters	Fuel Input, Residual Oil (Imported)
Air	
NO_x, lb	0.16(1)
SO_2, lb	0.45(2)
CO, lb	0
Particulate, lb	0.01(3)
Total organic material, lb	0.04(4)
Heat, 10^6 Btu	0.62(5)
Water	
Suspended solids, lb	0
Dissolved solids, lb	0
Total organic material, lb	0
Heat, 10^6 Btu	Negligible after cooling tower
Acid (H_2SO_4), lb	0
Solid	
Slag, lb	0
Ash, lb	3.0(6)
Sludge, lb	0
Tailings, lb	0
Hazardous, lb	0
By-Products	1.4(7)
Occupational Health	
Deaths	2×10^{-9}(8)
Total Injuries	7×10^{-8}(8)
Man Days Lost	1.7×10^{-5}(9)
Land Use, acre-hr/10^6 Btu	0.06(10)
Approx. Module Efficiency	38%(11)

Footnotes for Table 54:

(1) a. Experimental data obtained by Westinghouse.(A-23)

(2) a. SO_2 from boiler(A-23) = 0.35 lb/10^6 Btu.
b. SO_2 from Claus unit(A-23) = 0.1 lb/10^6 Btu.

(3) a. Electrostatic precipitator is employed to control particulate emission (assumed).
b. Particulate emission factor(A-23) = 0.01 lb/10^6 Btu.

(4) a. Hydrocarbon emission factor for burning CAFB gas (assumed) = 40 lb/10^6 ft^3.

(5) a. Efficiency of the module (assumed) = 38%.

(6) a. Sulfur content of oil (assumed) = 3%.
b. Limestone requirement per pound of sulfur = 1.75 lb.
c. Heating value of oil (assumed) = 6.3 x 10^6 Btu/bbl.

(7) a. Sulfur content of oil (assumed) = 3%.
b. Sulfur emission = 0.225.

(8) a. Injury rate per man hour (assumed) = 10 injuries/10^6 man hours.
b. Death rate of injury = 3%.
c. 70 men operate a 1000 MW plant (assumed).

(9) a. Man days lost per death (assumed) = 6000 days/death.
b. Man days lost per injury (assumed) = 95 days/injury.

(10) a. Land requirement for a 1000 MW oil-fired power plant (assumed) = 300 acres.
b. Additional land requirement for CAFB gas unit (assumed) = 150 acres.

(11) a. Assumed efficiency = 38%.

TABLE 55. ENVIRONMENTAL IMPACTS OF MODULE

Module--Conv. Boiler with limestone scrubber(1)
Unit--10^6 Btu (Input)

Environmental Impacts	Resid (3.5% S)
Air	
NO_x, lb	0.7
SO_2, lb	0.366(2)
CO, lb	0
Particulate, lb	0.0005(3)
Total organic material, lb	0.01
Water	
Suspended solids, lb	0
Dissolved solids, lb	0
Total organic material, lb	0
Solid	
Ash, lb	0
Sludge, lb	13.8(4)
Approx. Module Efficiency	37%

Footnotes for Table 55:

(1) a. Values were taken from Table A-42 in reference (A-26) except as modified below.

(2) a. Sulfur content of resid (assumed) = 3.5%.

b. SO_2 emission was considered twice that given in Table A-42 in reference (A-26).

c. SO_2 removal efficiency of lime scrubber (assumed) = 90%.

(3) a. Particulate emission factor(A-1) = 8 lbs/1000 gal.

b. Particulate removal efficiency (assumed) = 99%.

(4) a. SO_2 in sludge [from Footnote (2)] = 3.29 lb/10^6 Btu.

b. Generally sulfur in lime scrubber sludge is assumed as 12% by weight.

TABLE 56. ENVIRONMENTAL IMPACTS OF MODULE

Module--Conventional Boiler - No Control(1)
Unit--10^6 Btu (Input)

Environmental Impacts	Resid (3.5% S)
Air	
NO_x, lb	0.7
SO_2, lb	3.66(2)
CO, lb	0
Particulate, lb	0.05
Total organic material, lb	0.01
Water	
Suspended solids, lb	0
Dissolved solids, lb	0
Total organic material, lb	0
Solid	
Ash, lb	0
Sludge, lb	0
Approx. Module Efficiency	37%

Footnotes from Table 56:

(1) a. Emission values were taken from Table A-42 in reference (A-26) except as described below.

(2) a. In this module sulfur content of resid was assumed as 3.5%.

b. Thus SO_2 emission was considered to be twice that given in Table A-42 in reference (A-26).

TABLE 57. ENVIRONMENTAL DATA FOR MODULE

Module - Fluid-Bed Combustion Plus Combined Cycle
Unit - 10^6 Btu (input to combustion cycle)

Environmental Parameters	Fuel Input, Coal, East
Air	
NO_x, lb	0.14(1)
SO_2, lb	0.7(2)
CO, lb	0
Particulate, lb	0.02(3)
Total organic material, lb	0
Heat, 10^6 Btu	0.62(4)
Water	
Suspended solids, lb	0
Dissolved solids, lb	0
Total organic material, lb	0
Heat, 10^6 Btu	Negligible after cooling tower
Acid (H_2SO_4), lb	0
Solid	
Slag, lb	0
Ash, lb	17.3(5)
Sludge, lb	0
Tailings, lb	0
Hazardous, lb	0
By-Products	1.9(6)
Occupational Health	
Deaths	1.5×10^{-9}(7)
Total Injuries	3.6×10^{-8}(8)
Man Days Lost	1.4×10^{-5}(9)
Land Use, acre-hr/10^6 Btu	0.12(10)
Approx. Module Efficiency	38%(11)

Footnotes for Table 57:

(1) a. Average value of 0.07 and 0.22 lb/10^6 Btu reported in Westinghouse Report.(A-23)

(2) a. SO_2 emission factor reported(A-23) = 1 lb/10^6 Btu.
b. Adjustment factor for sulfur content(A-23) = 0.7 (i.e., $\frac{3.0}{4.3}$).

(3) a. Particulate emission factor reported(A-23) = 0.02 lb/10^6 Btu.

(4) a. Efficiency of the module (assumed) = 38%.

(5) a. Ash content of eastern coal (assumed) = 14.4%.
b. Heating value of coal (assumed) = 24 x 10^6 Btu/ton.
c. Limestone requirement per pound of sulfur = 1.75 lb.

(6) a. The sole by-product is elemental sulfur.
b. Sulfur content of coal (assumed) = 3%.
c. 90% of sulfur is collected by limestone (assumed).
d. Sulfur loss from Claus unit(A-23) = 0.35 lb/10^6 Btu.

(7) a. Injuries calculated from fluid-bed combustion plant and gas-fired power plant operations.
b. 40 men operate a 500 ton coal/hr capacity combustion plant (assumed).
c. Using chemical industry data for gasification plant, injuries per man hour(A-5) = 8.1 injuries/10^6 man hours.
d. Death rate (assumed) = 5% of injuries.
e. Death attributed to a 100 MW gas-fired power plant(A-12) = 0.01 deaths/year.

(8) a. Injuries attributed to a 1000 MW gas fired power plant(A-12) = 0.6 injuries/year.

(9) a. Using chemical industry data for gasification plant, man-days lost per man hour(A-5) = 528 days/10^6 man hours.
b. Man days lost per death (assumed) = 6000 days/death.
c. Man days lost attributed to a 1000 MW gas fired power plant(A-12) = 197 man-days/year.

(10) a. Land requirement for a 1000 MW coal fired power plant (assumed) = 800 acres.
b. Additional land requirement for fluid-bed combustion unit (assumed) = 150 acres.

(11) a. Efficiency(A-23) = 38%.

TABLE 58. ENVIRONMENTAL DATA FOR MODULE

Module - Lurgi Gasifier and Conventional Boiler
Unit - 10^6 Btu (input to conventional boiler)

Environmental Parameters	Fuel Input, Coal, East
Air	
NO_x, lb	0.40(1)
SO_2, lb	0.93(2)
CO, lb	0
Particulate, lb	0.015(3)
Total organic material, lb	0.11(4)
Heat, 10^6 Btu	0.92(5)
Water	
Suspended solids, lb	0.016(6)
Dissolved solids, lb	0
Total organic material, lb	0.002(7)
Heat, 10^6 Btu	Negligible after cooling tower
Phenols, lb	0.0029(8)
Solid	
Slag, lb	0
Ash, lb	9.82(9)
Sludge, lb	0
Tailings, lb	0
Hazardous, lb	0
By-Products	1.9(10)
Occupational Health	
Deaths	1.5×10^{-9}(11)
Total Injuries	3.6×10^{-8}(12)
Man Days Lost	9.4×10^{-6}(13)
Land Use, acre-hr/10^6 Btu	0.12(14)
Approx. Module Efficiency	25.9%(15)

Footnotes for Table 58:

(1) a. NO_x comes from gas-fired boiler in gasifier plant and gas-fired power plant.
    b. NO_x emission factor$^{(A-1)}$ = 0.39 lb/10^6 Btu for natural gas.
    c. The emission factor is value for Lurgi gas combustion on the basis of heating value (assumed).

(2) a. Basis: 1000 MW nominal cogas power plant.$^{(A-6)}$
    b. Coal input rate$^{(A-6)}$ = 341 tons/hr.
    c. SO_2 emission comes from gas-fired boiler in gasifier plant and gas-fired power plant.$^{(A-6)}$
    d. 1% of sulfur lost to atmosphere from gasifier plant by leaking (assumption).
    e. Content of H_2S in Lurgi gas produced$^{(A-6)}$ = 0.105% by volume.
    f. Lurgi gas production rate from the plant = 112600 lb-moles/hr.

(3) a. Particulate emission comes from gas-fired power plant (assumed).
    b. Emission factor for natural gas$^{(A-1)}$ = 0.015 lg/10^6 Btu.
    c. Assumed that the emission factor for natural gas combustion is valid to Lurgi gas combustion on the basis of heating value.

(4) a. 1% of total organic matter (COS and CH_4) is lost from gasifier by leaking (assumed).

(5) a. 63% of the total input energy to gas-fired power plant is lost to atmosphere (based on the assumed efficiency of the power plant).
    b. Efficiency of Lurgi gasifier plant (assumed) - 70%.
    c. Efficiency loss due to material loss in Lurgi gasifier plant (assumed) = 10%.

(6) a. Suspended solid emission comes from gas-fired power plant (assumed).
    b. Emission from a 1000 MW plant$^{(A-12)}$ = 548 tons.

(7) a. Total organic material comes from gas-fired power plant (assumed).
    b. Emission factor$^{(A-12)}$ = 73 tons/year for a 1000 MW plant.

(8) a. From data supplied by T. K. Janes, EPA.

(9) a. Ash content of coal (assumed) = 14.4%.

(10) a. The by-product of Lurgi gasifier plant is sulfur from Claus unit.

(11) a. Injuries are combined for Lurgi gasifier plant and gas-fired power plant operations.
    b. 40 men operate a 500-ton coal/hr capacity Lurgi gasifier plant (assumed).
    c. Using chemical industry data, injuries per man-hour$^{(A-5)}$ = 8.1 injuries/10^6 man-hours.
    d. Death rate (assumed) = 5% of total injuries.
    e. Death attributed to a 1000 MW gas-fired power plant$^{(A-12)}$ = 0.01 death/year.

(12) a. Injuries attributed to a 1000 MW gas-fired power plant$^{(A-12)}$ = 0.6 injuries/year.

(13) a. Using chemical industry data, days lost per man-hour$^{(A-5)}$ = 528 days/10^6 man-hours.
    b. Man-days lost per death (assumed) = 6000 days/death
    c. Man-days lost attributed to a 1000 MW gas-fired power plant$^{(A-13)}$ = 197 man days/year.

(14) a. Land requirement for a 1000 MW coal-fired power plant (assumed) = 800 acres.
    b. Additional land requirement for Lurgi gasifier plant (assumed) = 150 acres.

(15) a. Efficiency of Lurgi gasifier plant (assumed) = 70%.
    b. Efficiency of gas-fired power plant (assumed) = 37%.

TABLE 59. ENVIRONMENTAL IMPACTS OF MODULE (1)
Module-- Conv. Boiler, Phys. Cleaned Coal
Unit--10^6 Btu (Input)

Environmental Impacts	Phys. Cleaned Coal
Air	
NO_x, lb	0.68
SO_2, lb	1.44
CO, lb	0.038
Particulate, lb	0.044
Total organic material, lb	0.011
Water	
Suspended solids, lb	0.025
Dissolved solids, lb	0
Total organic material, lb	0.011
Solid	
Ash, lb	5.41
Sludge, lb	0
Approx. Module Efficiency	37%

Footnotes for Table 59:

(1) a. Data were taken from Table A-10 in reference (A-26) except that SO_2 emission were corrected to 1% sulfur in cleaned coal.

TABLE 60. ENVIRONMENTAL DATA FOR MODULE

Module - Coal Liquefaction (solvent refining)
Unit - 10^6 Btu (output)

Environmental Parameters	Fuel Input, Eastern Coal[(1)]
Air	
NO_x, lb	0.21[(2)]
SO_2, lb	0.003[(3)]
CO, lb	0.012[(4)]
Particulate, lb	0.27[(5)]
Total organic material, lb	0.0036[(6)]
Heat, 10^6 Btu	0.067[(7)]
Water	
Suspended solids, lb	0
Dissolved solids, lb	0
Total organic material, lb	Trace
Heat, 10^6 Btu	Negligible after cooling tower
Acid (H_2SO_4), lb	0
Solid	
Slag, lb	0
Ash, lb	16.0[(8)]
Sludge, lb	0
Tailings, lb	0
Hazardous, lb	0
By-Products	2.95[(9)]
Occupational Health	
Deaths	1.4×10^{-9}[(10)]
Total Injuries	2.7×10^{-8}[(10)]
Man Days Lost	6.5×10^{-6}[(11)]
Land Use, acre-hr/10^6 Btu	0.08[(12)]
Approx. Module Efficiency	75%[(13)]

(1) Impacts were estimated based on the coal containing 14.4% ash, 3.0% S and a heating value of 12,000 Btu/lb. In addition, the coal liquefaction plant was assumed to have a capacity of 222×10^9 Btu/day.

Footnotes for Table 60: (Continued)

(2) a. Solvent refined coal (SRC) has a heating value of 16,000 Btu/lb, 0.05% ash, and 0.6% sulfur(A-6).
b. Plant efficiency(A-6) = 75%.
c. Emission factor for NO_x = 18 lb/ton of coal burned.
d. Average heating value of consumed coal = 14,000 Btu/lb.
e. Coal consumption rate = 110 tons/hr.

(3) a. Total sulfur content in the input coal = 30,833 lb/hr.
b. Total sulfur content in the SRC = 3.469 lb/hr.
c. Sulfur emitted as SO_2 = 0.1% total sulfur off gas-liquid separator.

(4) a. CO emission factor(A-1) = 1 lb/ton of coal burned.
b. No control equipment.

(5) a. Particulate emission factor(A-1) = 16A lb/ton of coal burned.
b. Emission control efficiency (assumed) 98%.
c. Average ash content of consumed coal, A = 7.23%.

(6) a. Total organic material emission factor = 0.3 lg/ton of coal burned.
b. No control equipment.

(7) a. Total heat released = 0.308 x 10^{10} Btu/hr.

(8) a. Total ash input rate = 148,000 lb/hr.
b. Total ash output rate in SRC = 289 lb/hr.

(9) Elemental sulfur product = 99.9% of total sulfur-off gas, liquid separator.

(10) a. Assumption: 80 men operate a 1,000 ton/hr capacity solvent refining plant.
b. Use chemical industry data, injuries per man hour(A-5) = 8.1 injuries/10^6 man hours.
c. Use chemical industry data, days lost per man hour(A-5) = 528 days lost/10^6 man hours.
d. Death rate = 5% of total injuries (assumed).

(11) Man days lost per death (assumed) = 6,000 days/death.

(12) Land required for a 222 x 10^9 Btu/day plant (assumed) = 750 acres.

(13) Plant efficiency(A-6) = 75%.

TABLE 61. ENVIRONMENTAL DATA FOR MODULE

Module - Conventional Boiler
Unit - 10^6 Btu (input)

Environmental Parameters	Fuel Input, Solvent Refined Coal (Eastern)
Air	
NO_x, lb	0.56(1)
SO_2, lb	0.71(2)
CO, lb	0.037(3)
Particulate, lb	0.0003(4)
Total organic material, lb	0.01(5)
Heat, 10^6 Btu	0.63(6)
Water	
Suspended solids, lb	0.025(7)
Dissolved solids, lb	0
Total organic material, lb	0.011(8)
Heat, 10^6 Btu	Negligible after cooling tower
Acid (H_2SO_4), lb	0
Solid	
Slag, lb	0
Ash, lb	0.031(9)
Sludge, lb	0
Tailings, lb	0
Hazardous, lb	0
By-Products	
Occupational Health	
Deaths	3.3×10^{-10}(10)
Total Injuries	1.4×10^{-8}(10)
Man Days Lost	5.1×10^{-6}(11)
Land Use, acre-hr/10^6 Btu	0.09(12)
Approx. Module Efficiency	37%(13)

Footnotes for Table 61:

(1) a. NO_x emissions factor$^{(A-1)}$ = 18 lb/ton coal burned.
b. Heating value of solvent refined coal (SRC) (assumed) = 16000 Btu/lb.

(2) a. Sulfur content of solvent refined coal, S (assumed) = 0.6%.
b. SO_2 emission factor$^{(A-1)}$ = 38 S lb/ton coal burned.

(3) a. CO emission factor$^{(A-1)}$ = 1 lb/ton coal burned.

(4) a. Ash content of SRC, A (assumed) = 0.05%.
b. Particulate emission factor$^{(A-1)}$ = 16 A lb/ton coal burned.
c. Electrostatic precipitator efficiency (assumed) = 99%.

(5) a. Hydrocarbon emission factor$^{(A-1)}$ = 0.3 lb/ton coal burned.

(6) a. Efficiency of conventional boiler (assumed) = 37%.

(7) a. Total solid to water$^{(A-12)}$ = 0.036 lb/10^6 Btu.
b. Fraction of suspended solids (assumed) = 70%.

(8) a. Fraction of organic material in total solid (assumed) = 30%.

(9) a. Ash content of coal (assumed) = 0.05%.

(10) a. Man-hour required per 10^6 Btu for conventional power plant$^{(A-13)}$ = 2.4×10^{-3} man hour/10^6 Btu.
b. Total injuries per 10^6 man hour$^{(A-13)}$ = 5.7.
c. Death rate$^{(A-12)}$ = 2.4% of injuries.

(11) a. Days lost per death (assumed) = 6000 days/death.
b. Days lost per injuries (assumed) = 229 days/injury.

(12) a. Land requirement for a 1000 MW power plant (assumed) = 700 acres.

(13) a. Efficiency of conventional boiler (assumed) = 37%.

TABLE 62. ENVIRONMENTAL DATA FOR MODULE

Module - Conventional Boiler and Limestone Scrubbing
Unit - 10^6 Btu (input)

Environmental Parameters	Fuel Input, Coal, East
Air	
NO_x, lb	0.60(1)
SO_2, lb	0.50(2)
CO, lb	0.042(3)
Particulate, lb	0.1(4)
Total organic material, lb	0.013(5)
Heat, 10^6 Btu	0.65(6)
Water	
Suspended solids, lb	0.025(7)
Dissolved solids, lb	0
Total organic material, lb	0.011(8)
Heat, 10^6 Btu	Negligible after cooling tower
Acid (H_2SO_4), lb	0
Solid	
Slag, lb	0
Ash, lb	2.4(9)
Sludge, lb	27.3(10)
Tailings, lb	0
Hazardous, lb	0
By-Products	0
Occupational Health	
Deaths	3.3×10^{-10}(11)
Total Injuries	1.4×10^{-8}(11)
Man Days Lost	5.1×10^{-6}(12)
Land Use, acre-hr/10^6 Btu	0.1(13)
Approx. Module Efficiency	35%(14)

Footnotes for Table 62:

(1) a. NO_x emission factor$^{(A-1)}$ = 18 lb/ton coal burned.
b. Heating value of eastern coal (assumed) = 12000 Btu/lb.
c. NO_x removal efficiency by limestone scrubber (assumed) = 20%.

(2) a. Sulfur content of eastern coal, S (assumed) = 3%.
b. SO_2 emission factor$^{(A-1)}$ = 38 S lb/ton coal burned.
c. Limestone scrubber efficiency (assumed) = 90%.

(3) a. CO emission factor$^{(A-1)}$ = 1 lb/ton coal burned.

(4) a. Ash content of eastern coal, A (assumed) = 14.4%.
b. Particulate emission factor$^{(A-1)}$ = 16 A lb/ton coal burned.
c. Scrubber efficiency for particulate removal = 99%.

(5) a. Hydrocarbon emission factor$^{(A-1)}$ = 0.3 lb/ton coal burned.

(6) a. Efficiency of conventional boiler with limestone scrubbing (assumed) = 35%.

(7) a. Total solid to water$^{(A-12)}$ = 0.036 lb/10^6 Btu.
b. Fraction of suspended solids (assumed) = 70%.

(8) a. Fraction of organic material in total solid (assumed) = 30%.

(9) a. Ash content of eastern coal (assumed) = 14.4%. 20% to bottom ash.

(10) a. Sulfur content of sludge (assumed) = 12%. Add fly ash collected.

(11) a. Man-hour required per 10^6 Btu for conventional power plant$^{(A-13)}$ = 2.4×10^{-3} man hour/10^6 Btu.
b. Total injuries per 10^6 Man hour$^{(A-13)}$ = 5.7.
c. Death rate$^{(A-12)}$ = 2.4% of injuries.

(12) a. Days lost per death (assumed) = 6000 days/death.
b. Days lost per injury (assumed) = 229 days/injury.

(13) a. Land requirement for a 1000 MW power plant (assumed) = 800 acres.

(14) a. Efficiency of conventional boiler with limestone scrubbing (assumed) = 35%.

TABLE 63. ENVIRONMENTAL DATA FOR MODULE

Module - Conventional Boiler & MgO-Scrubbing
Unit - 10^6 Btu (Input)

Environmental Parameters	Input: Eastern Coal
Air	
NO_x, lb	0.60(1)
SO_2, lb	0.50(2)
CO, lb	0.042(3)
Particulate, lb	0.1(4)
Total organic material, lb	0.013(5)
Heat, 10^6 Btu	0.65(6)
Water	
Suspended solids, lb	0.025(7)
Dissolved solids, lb	0
Total organic material, lb	0.011(8)
Heat, 10^6 Btu	Negligible after cooling tower
Acid (H_2SO_4), lb	0
Solid	
Slag, lb	0
Ash, lb	2.4(9)
Sludge, lb	0
Tailings, lb	10.4(10)
Hazardous, lb	0
By-Products	6.13(11)
Occupational Health	
Deaths	3.3×10^{-10}(12)
Total Injuries	1.4×10^{-8}(12)
Man Days Lost	5.1×10^{-6}(13)
Land Use, acre-hr/10^6 Btu	0.1(14)
Approx. Module Efficiency	35%(15)

Footnotes for Table 63:

(1) a. NO_x emission factor(A-1) = 18 lb/ton coal burned.
b. Heating value of eastern coal (assumed) = 12,000 Btu/lb.
c. NO_x removal efficiency by MgO-scrubber (assumed) = 20%.

(2) a. Sulfur content of eastern coal, S (assumed) = 3%.
b. SO_2 emission factor(A-1) = 38 S lb/ton coal burned.
c. MgO-scrubber efficiency (assumed) = 90%.

(3) a. CO emission factor(A-1) = 1 lb/ton coal burned.

(4) a. Ash content of eastern coal, A (assumed) 14.4%.
b. Particulate emission factor(A-1) = 16 A lb/ton coal burned.
c. Scrubber efficiency for particulate removal = 99%.

(5) a. Hydrocarbon emission factor(A-1) = 0.3 lb/ton coal burned.

(6) a. Efficiency of conventional boiler with MgO-scrubbing (assumed) = 35%.

(7) a. Total solid to water(A-12) = 0.036 lb/10^6 Btu.
b. Fraction of suspended solids (assumed) = 70%.

(8) a. Fraction of organic material in total solid (assumed) = 30%.

(9) a. Ash content of eastern coal (assumed) = 14.4%. 20% to bottom ash.

(10) a. MgO reacts with SO_2 to product 80% of $MgSO_3 \cdot 6H_2O$ and 20% of $MgSO_4 \cdot 7H_2O$ (assumption).
b. 1% blowdown of $MgSO_3 \cdot 6H_2O$ and $MgSO_4 \cdot 7H_2O$ (assumed).
c. Loss in regeneration (assumed) = 5%. Add fly ash collected.

(11) a. Sulfur reacted with MgO is regenerated in the form of H_2SO_4.
b. Regeneration efficiency (assumed) = 100%.

(12) a. Man-hour required per 10^6 Btu for conventional power plant(A-13) = 2.4×10^{-3} man-hour/10^6 Btu.
b. Total injuries per 10^6 man hour(A-13) = 5.7.
c. Death rate(A-12) = 2.4% of injuries.

(13) a. Days lost per death (assumed = 6000 days/death.
b. Days lost per injury (assumed) = 229 days/injury.

(14) a. Land requirement for a 1000 MW power plant (assumed) = 800 acres.

(15) a. Efficiency of conventional boiler with MgO-scrubbing (assumed) = 35%.

TABLE 64. ENVIRONMENTAL DATA FOR MODULE

Module - Conventional Boiler
Unit - 10^6 Btu (Input)

Environmental Parameters	Fuel Input, Eastern Coal
Air	
NO_x, lb	0.75(1)
SO_2, lb	4.75(2)
CO, lb	0.042(3)
Particulate, lb	0.1(4)
Total organic material, lb	0.013(5)
Heat, 10^6 Btu	0.63(6)
Water	
Suspended solids, lb	0.025(7)
Dissolved solids, lb	0
Total organic material, lb	0.011(8)
Heat, 10^6 Btu	Negligible after cooling tower
Acid (H_2SO_4), lb	0
Solid	
Slag, lb	0
Ash, lb	12.0(9)
Sludge, lb	0
Tailings, lb	0
Hazardous, lb	0
By-Products	0
Occupational Health	
Deaths	3.3×10^{-10}(10)
Total Injuries	1.4×10^{-8}(10)
Man Days Lost	5.1×10^{-6}(11)
Land Use, acre-hr/10^6 Btu	0.1(12)
Approx. Module Efficiency	37%(13)

Footnotes for Table 64:

(1) a. NO_x emission factor$^{(A-1)}$ = 18 lb/ton of coal burned.

(2) a. SO_2 emission factor$^{(A-1)}$ = 38 S lb/ton of coal burned.
    b. Sulfur content, S (assumed) = 3%.

(3) a. CO emission factor$^{(A-1)}$ = 1 lb/ton coal burned.

(4) a. Particulate emission factor$^{(A-1)}$ = 16A lb/ton coal burned.
    b. Ash content, A (assumed) = 14.4%.
    c. Electrostatic precipitator efficiency (assumed) = 99%.

(5) a. Hydrocarbons emission factor$^{(A-1)}$ = 0.3 lb/ton coal burned.

(6) a. Efficiency of conventional boiler (assumed) = 37%.

(7) a. Total solid to water$^{(A-12)}$ = 0.036 lb/10^6 Btu.
    b. Fraction of suspended solid (assumed) = 70%.

(8) a. Fraction of organic material in total solid (assumed) = 30%.

(9) a. Ash content of coal (assumed) = 14.4%

(10) a. Man-hours required per 10^6 Btu for conventional power plant$^{(A-13)}$ = 2.4×10^{-3} man-hour/10^6 Btu.
    b. Total injuries per 10^6 man hour$^{(A-13)}$ = 5.7.
    c. Death rate$^{(A-12)}$ = 2.4% of injuries.

(11) a. Days lost per death (assumed) = 6000 days/death.
    b. Days lost per injury (assumed) 229 days/injury.

(12) a. Land required for a 1000 MW power plant (assumed) = 800 acres.

(13) a. Efficiency of conventional boiler (assumed) = 37%.

TABLE 65. ENVIRONMENTAL DATA FOR MODULE

Module - Strip Mined Coal, East
Unit - 10^6 Btu (output)

Environmental Parameters	With Land Restoration and Treatment of Acid Drainage(1)
Air	
NO_x, lb	0.0002(2)
SO_2, lb	Negligible
CO, lb	Negligible
Particulate, lb	0.14(3)
Total organic material, lb	Negligible
Heat, 10^6 Btu	Negligible
Water	
Suspended solids, lb	0.55(4)
Dissolved solids, lb	0.18
Total organic material, lb	Negligible
Heat, 10^6 Btu	Negligible
Acid (H_2SO_4), lb	Nil
Solid	
Slag, lb	0
Ash, lb	0
Sludge, lb	0.24(5)
Tailings, lb	Negligible
Hazardous, lb	0
By-Products	None
Occupational Health	
Deaths	5×10^{-9}(6)
Total Injuries	2.5×10^{-7}(7)
Man Days Lost	7.4×10^{-5}(8)
Land Use, acre-hr/10^6 Btu	0.3(9)
Approx. Module Efficiency	99.6%(10)

Footnotes for Table 65:

(1) Impacts will be negligible after land restoration. Stated impacts will occur during the actual operation.

(2) a. NO_x released to atmosphere from reclamation operation was derived based on the assumption that a diesel powered bulldozer is used for reclamation.
b. Time requirement for reclamation (assumed) = 4 hr/acre.
c. Bulldozer engine power (assumed) = 150 hp.
d. Fuel consumption rate(A-1) = 0.5 lb/hp-hr.
e. Emission factor(A-1) = 0.37 lb NO_x/gal of fuel used.
f. Average thickness of coal seam (assumed) = 2 ft.
g. Coal density (assumed) = 82 lb/ft^3.
h. Heating value of coal (assumed) = 12,000 Btu/lb.

(3) a. Emission factor (same as primary rock crushing and copper mining) = 0.1 lb/ton of overburden.
b. Average overburden per ton of coal (private communication, EPA) = 33 tons.

(4) a. Rate of silt run-off (assumed = 5000 tons/Mi^2-year.
b. Average thickness of coal seam (assumed) = 2 ft.
c. Coal bulk density (assumed) = 82 lb/ft^3.
d. Reclamation period (assumed) = 3 years

(5) a. Dissolved solids ($CaSO_4$) and sludge ($FeOH_2$) come from acid treatment (assumed).
b. Drainage water discharge rate for a strip coal mine with a capacity of 10^6 ton coal/year (assumed) = 10^6 gal/day.
c. Acidity of drainage water (assumed) = 1000 ppm.

(6) a. Death rate for strip coal mining(A-12) = 0.12/10^6 ton coal.
b. Heating value of coal (assumed) = 24 x 10^6 Btu/ton coal.

(7) a. Injury rate for strip coal mining(A-12) = 5.65 injuries/10^6 ton coal.

(8) a. Man-days lost per death (assumed) = 6000 days/death.
b. Man-days lost per injury (assumed) = 180 days/injury.

(9) a. Land required for 10^6 tons of coal(A-12) = 280 acres.
b. Time required for reclamation (assumed) = 3 years.

(10) a. Efficiency of strip mine operation (assumed) = 99.6%.
b. Depletive waste not included.

TABLE 66. ENVIRONMENTAL IMPACTS OF MODULE

Module--Coke Oven(1)
Unit--10^6 Btu (Input)

Environmental Impacts	Coal, West
Air	
NO_x, lb	0.0017(2)
SO_2, lb	0.8(3)
CO, lb	0.053(2)
Particulate, lb	0.146(2)
Total organic material, lb	0.175(2)
Water	
Suspended solids, lb	--
Dissolved solids, lb	--
Total organic material, lb	--
Solid	
Ash, lb	0
Sludge, lb	0
Approx. Module Efficiency	70%

Footnotes for Table 66:

(1) a. Low sulfur coal (0.95% S) was assumed in the coke oven operation.

b. Heating value of coal (assumed) = 12,000 Btu/lb coal.

(2) a. Emission factors were taken from reference (A-1).

(3) a. Based on assumption that 50% of sulfur in coal remains in the coke and 50% ultimately is emitted as SO_2.

TABLE 67. ENVIRONMENTAL IMPACTS OF MODULE

Module--Space Heating(1)
Unit--10^6 Btu (Input)

Environmental Impacts	Resid (3.5% S)
Air	
NO_x, lb	0.135
SO_2, lb	3.068(2)
CO, lb	0.030
Particulate, lb	0.017
Total organic material, lb	0.004
Water	
Suspended solids, lb	0
Dissolved solids, lb	0
Total organic material, lb	0
Solid	
Ash, lb	0
Sludge, lb	0
Approx. Module Efficiency	70%

Footnotes for Table 67:

(1) a. Values were taken from Table A-46 in reference (A-26) except as modified below.

(2) a. SO_2 emission was modified based on sulfur content of fuel oils.

TABLE 68. ENVIRONMENTAL IMPACTS OF MODULE

Module--Space Heating(1)
Unit--10^6 Btu (Input)

Environmental Impacts	Coal (3% S)
Air	
NO_x, lb	0.177
SO_2, lb	4.410(2)
CO, lb	3.490
Particulate, lb	0.775
Total organic material, lb	0.775
Water	
Suspended solids, lb	0
Dissolved solids, lb	0
Total organic material, lb	0
Solid	
Ash, lb	6.9
Sludge, lb	0
Approx. Module Efficiency	50%

Footnotes for Table 68:

(1) a. Values were identical to those in Table A-12 except as modified below.

(2) a. SO_2 emission was modified based on sulfur content of coal.

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APPENDIX B

CALCULATION OF PREDICTED AMBIENT AIR QUALITY FOR THE INDIANAPOLIS AQCR

The calculations required for the determination of ambient air quality to be expected from fuel combustion in the Indianapolis AQCR according to projections based on Scenario 1 and Scenario 3 are presented in this appendix. The Indianapolis AQCR inventory was modified as indicated in the discussion in the body of the report. The resulting base-case data are given in Table 69. These data refer to 1971 fuel quantities and the emissions and AAQ are based on the use of all clean fuel.

The approach will be illustrated by describing the calculations required for 1975. The base-case data (Table 69) were first increased by a growth factor, 1.101, determined by dividing the Dupree and West projected coal use as fuel in 1975 (13,675 x 10^{12} Btu) by the actual 1971 value (12,420 x 10^{12} Btu). The results of the growth factor multiplication are given in the first three lines of Table 70. These data represent the coal use for the Indianapolis AQCR for 1975 and the SO_2 emissions and AAQ which would result if all the coal were low sulfur coal.

The total coal use was broken down into high- or low-sulfur coal use and into various energy technology applications in direct proportion to the fuel utilization projections developed in the body of the report. For convenience, the coal allocations for 1975 were summarized from Tables 6, 7, and 8 for Scenario 1 and from Tables 19, 20, and 21 for Scenario 3. This summary is given in Table 71. For certain of these allocations the percentage of the total is also given in Table 71. For example, in Scenario 1 the high-sulfur coal use in the electrical sector was projected to be 5,775 x 10^{12} Btu, or 42.23 percent of the total. These percentages were then applied to the total coal use projected for the Indianapolis AQCR in 1975. Thus, in Scenario 1, 42.23 percent of the projected total coal, or 1,807,146 tons per year, are allocated as high-sulfur coal to the electrical sector. The results of these calculations are given in the coal-use column of Table 70. The quantities of low-sulfur coal were adjusted to balance the subtotals for each sector.

Each coal-use quantity was multiplied by the emission factor appropriate to the coal type or applied energy technology to obtain the equivalent SO_2 emissions in tons per day as given in Table Table 70.

The SO_2 emissions were summed for each sector and the resulting AAQ contribution calculated for each sector in proportion to the corresponding base-case values. The necessary calculations are shown in Table B-2.

Finally, the sector contributions to AAQ were summed to obtain the total predicted AAQ from coal combustion according to Scenario 1, 43.15 $\mu g/m^3$, and according to Scenario 3, 105.16 $\mu g/m^3$.

These calculations were repeated for the remaining years and the resulting data are given in Tables 72 and 73 for 1980, in Tables 74 and 75 for 1985, and in Tables 76 and 77 for 2000.

It was pointed out in the body of the report that the total emissions calculated for Scenario 3 were larger than for Scenario 1 in 1980, 1985, and 2000 as a result of removing some stack gas cleaning capacity to balance the coal subtotal in the electrical sector. The same result is, of course, observed in Tables 72, 74, and 76. However, it should be noted that it is not the increase in emissions per se which is responsible for the large increase in AAQ observed for Scenario 3, but rather, it is the occurrence of increased emissions in the nonelectrical sectors which is responsible for the increased AAQ. For example, consider the year 2000, Table 76; assume that the same quantity of high sulfur coal (1,131,813 tons/year) projected for Scenario 3 is included in the electrical sector for Scenario 1, and that the low sulfur coal projection for Scenario 1 is reduced by the same amount to balance the subtotal. Also assume that the stack gas cleaning capacity projected for Scenario 1 is retained in Scenario 3 and the low-sulfur coal in Scenario 3 is reduced to balance the subtotal. Now the only difference between the two scenarios is the interchange of high- and low-sulfur coal between the electrical and the nonelectrical sectors. When the AAQ calculations are repeated with these modified coal-use quantities, the results are as follows:

	SO_2 Emissions, Tons/Day	AAQ-R33 $\mu g/m^3$
Scenario 1		
Electrical Sector	313.8	14.7
Other Sectors	91.2	54.6
Totals	405.0	60.3
Scenario 3		
Electrical Sector	192.2	9.0
Other Sectors	218.3	130.6
Totals	410.5	139.6

In this case the total emissions are nearly equal, yet the AAQ for Scenario 3 is still more than twice that for Scenario 1.

TABLE 69. INDIANAPOLIS BASE CASE-1971[(a,b)]

	Coal use, Tons/Year	SO_2 Emissions, Tons/Day	AAQ-Receptor 33, $\mu g/m^3$
Electrical Sector	3,001,038	156.9	7.35
Other Sectors	885,697	40.7	24.39
Totals, All Sectors	3,886,735	197.6	31.74

(a) Assumed all clean fuels.

(b) Processing plants have been excluded from this table. Seven plants emitted 3.29 T/D SO_2 and contributed 14.78 $\mu g/m^3$ to Receptor 33.

TABLE 70. PREDICTED AMBIENT AIR QUALITY - 1975

Sector/Combustion Mode	Coal Use, Tons/Year	SO_2 Emissions, Tons/Day	AAQ - Receptor 33 $\mu g/m^3$
Indianapolis Base Case (Growth Factor, 1.101, applied to 1971 Base Case)			
Electrical Sector	3,304,143	172.8	8.09
Other Sectors	975,152	44.8	26.85
Totals, all sectors	4,279,295	217.6	34.95
Scenario 1			
Electrical Sector			
Stack gas cleaning	219,099 (5.12%)	3.60	
High sulfur coal, w/o cont.	1,807,146 (42.23%)	282.20	
Low sulfur coal	1,277,898 (Bal.)	62.31	
Subtotals	3,304,143	348.11	16.30 (348.11/172.8 x 8.09)
Other Sectors (Unchanged)	975,152	44.8	26.85
Totals, all sectors	4,279,295	392.93	43.15
Scenario 3			
Electrical Sector			
Stack gas cleaning	219,099 (5.12%)	3.60	
High sulfur coal, w/o cont.	946,580 (22.12%)	147.88	
Low sulfur coal	2,138,099 (Bal.)	104.25	
Subtotals	3,304,143	255.73	11.98 (255.73/172.8 x 8.09)
Other Sectors			
High sulfur coal, w/o cont.	860,201 (20.11%)	149.95	
Low sulfur coal	114,951 (Bal.)	5.60	
Subtotals	975,152	155.58	93.18 (155.55/44.82 x 26.85)
Totals, all sectors	4,279,295	411.28	105.16

TABLE 71. YEAR 1975 COAL ALLOCATIONS

Sector	Scenario 1		Scenario 3	
	10^{12} Btu	Percent of Total	10^{12} Btu	Percent of Total
Residential/Commercial				
Low sulfur coal	325		80	
High sulfur coal	0		245	
Industrial				
Low sulfur coal	4,450		1,945	
High sulfur coal	0		2,505	
Totals, R/C plus Industrial				
Low sulfur coal	4775		2025	
High sulfur coal	0		2,750	20.11
Electrical				
Low sulfur coal	2,425		5,175	
Stack gas cleaning	700	5.12	700	5.12
High sulfur coal	5,775	42.23	3,025	22.12
Total, all sectors	13,675		13,675	

TABLE 72. PREDICTED AMBIENT AIR QUALITY - 1980

Sector/Combustion Mode	Coal Use, Tons/Year	SO_2 Emissions, Tons/Day	AAQ - Receptor 33 $\mu g/m^3$
Indianapolis Base Case (Growth Factor, 1.273, applied to 1971 Base Case)			
Electrical Sector	3,820,321	199.7	9.36
Other Sectors	1,127,492	51.8	31.05
Totals	4,947,813	251.5	40.41
Scenario 1			
Electrical Sector			
Stack gas cleaning	2,121,622 (42.88%)	34.88	
High sulfur coal, w/o cont.	178,616 (3.61%)	27.89	
Low sulfur coal	1,520,083 (Bal.)	74.11	
Subtotals	3,820,321	136.88	6.42 (136.88/197.7 x 9.36)
Other Sectors (Unchanged)	1,127,492	51.8	31.05
Totals, all sectors	4,947,813	188.68	37.47
Scenario 3			
Electrical Sector			
Stack gas cleaning	1,412,600 (28.55%)	23.22	
High sulfur coal, w/o cont.	0		
Low sulfur coal	2,407,721 (Bal.)	117.39	
Subtotals	3,820,321	140.61	6.59 (140.6/199.7 x 9.36)
Other Sectors			
High sulfur coal, w/o cont.	887,638 (17.94%)	138.62	
Low sulfur coal	239,855 (Bal.)	11.69	
Subtotals	1,127,492	150.31	90.1 (150.3/51.8 x 31.05)
Totals, all sectors	4,947,813	290.92	96.69

TABLE 73. YEAR 1980 COAL ALLOCATIONS

Sector	Scenario 1		Scenario 3	
	10^{12} Btu	Percent of Total	10^{12} Btu	Percent of Total
Residential/Commercial				
Low sulfur coal	300		75	
High sulfur coal	0		225	
Industrial				
Low sulfur coal	4,550		1,993	
High sulfur coal	0		2,557	
Totals, R/C plus Industrial				
Los sulfur coal	4,850		2,068	
High sulfur coal	0		2,282	17.94
Electrical				
Los sulfur coal	3,450		6,232	
Stack gas cleaning	6,650	42.88	4,428	28.55
High sulfur coal w/o control	560	3.61	0	
Total, all sectors	15,510		15,510	

TABLE 74. PREDICTED AMBIENT AIR QUALITY - 1985

Sector/Combustion Mode	Coal Use, Tons/Year	SO_2 Emissions, Tons/Day	AAQ - Receptor 33 μg/m^3
Indianapolis Base Case (Growth Factor, 1.654, applied to 1971 Base Case)			
Electrical Sector	4,963,717	259.5	12.16
Other Sectors	1,464,943	67.4	40.34
Totals	6,428,660	326.9	52.50
Scenario 1			
Electrical Sector			
Fluidized-bed	134,359 (2.09%)	3.1	
Low Btu	161,359 (2.51%)	4.9	
Liquefaction	100,300 (1.57%)	2.3	
Stack gas cleaning	2,337,461 (36.36%)	38.4	
Low sulfur coal	2,230,238 (Bal.)	108.7	
High sulfur coal, w/o cont.	0		
Subtotals	4,963,717	157.4	7.4 (157.4/259.5 x 12.16)
Other Sectors (Unchanged)	1,464,943	67.4	40.3
Totals	6,428,660	224.8	47.7
Scenario 3			
Electrical Sector			
Fluidized-bed	134,359 (2.09%)	3.1	
Low Btu	161,354 (2.09%)	4.9	
Liquefaction	100,300 (1.57%)	2.3	
Stack gas cleaning	1,083,579 (21.83%)	17.8	
Low sulfur coal	3,484,120 (Bal.)	169.9	
High sulfur coal, w/o cont.	0		
Subtotals	4,963,717	198.0	9.3 (198.0/259.5 x 12.16)
Other Sectors			
High sulfur coal, w/o cont.	921,227 (14.33%)	143.9	
Low sulfur coal	543,716 (Bal.)	26.5	
Subtotals	1,464,943	170.4	102.0 (170.4/67.4 x 40.34)
Totals, all sectors	6,428,660	368.4	111.3

TABLE 75. YEAR 1985 COAL ALLOCATIONS

Sector	Scenario 1		Scenario 3	
	10^{12} Btu	Percent of Total	10^{12} Btu	Percent of Total
Residential/Commercial				
Low sulfur coal	100		25	
High sulfur coal w/o control	0		75	
Industrial				
Low sulfur coal	4,820		2,113	
High sulfur coal	0		2,707	
Totals, R/C plus Industrial				
Low sulfur coal	4,920		2,138	
High sulfur coal	0		2,782	14.33
Electrical				
Fluidized-bed combustion	400	2.09	400	2.09
Gasification, low Btu	480	2.51	480	2.51
Liquefaction	300	1.57	300	1. 57
Stack gas cleaning	6,960	36.36	4,178	21.83
Low sulfur coal	6,080		8,862	
High sulfur coal, w/o control	0		0	
Totals, all sectors	19,140		19,140	

TABLE 76. PREDICTED AMBIENT AIR QUALITY - 2000

Sector/Combustion Mode	Coal Use, Tons/Year	SO_2 Emissions, Tons/Day	AAQ - Receptor 33 $\mu g/m^3$
Indianapolis Base Case (Growth Factor, 2.24, applied to 1971 Base Case)			
Electrical Sector	6,722,325	351.5	16.46
Other Sectors	1,983,961	91.2	54.64
Totals	8,706,286	422.7	71.10
Scenario 1			
Electrical Sector			
Fluidized-bed combustion	1,140,523 (13.1%)	26.2	
Low Btu gasification	1,453,950 (16.7%)	44.5	
Liquefaction	957,691 (11.0%)	22.4	
Stack gas cleaning	1,715,138 (19.7%)	28.2	
Low sulfur coal	1,455,023 (Bal.)	70.9	
High sulfur coal, w/o cont.	0		
Subtotals	6,722,325	192.2	9.0 (192.2/351.5 x 16.46)
Other Sectors (Unchanged)	1,983,961	91.2	54.6
Totals, all sectors	8,706,286	283.4	53.6
Scenario 3			
Electrical Sector			
Fluidized-bed combustion	1,140,523 (13.1%)	26.2	
Low Btu gasification	1,453,950 (16.7%)	44.5	
Liquefaction	957,691 (11.0%)	22.4	
Stack gas cleaning	583,321 (6.7%)	9.6	
Low sulfur coal	2,586,840 (Bal.)	126.1	
High sulfur coal, w/o cont.	0		
Subtotals	6,722,325	228.8	10.7 (228.8/351.5 x 16.46)
Other Sectors			
High sulfur coal, w/o cont.	1,131,817 (13.0%)	176.7	
Low sulfur coal	852,144 (Bal.)	41.5	
Subtotals	1,983,961	218.3	130.6 (218.3/91.2 x 54.64)
Totals, all sectors	8,706,286	447.1	141.3

TABLE 77. YEAR 2000 COAL ALLOCATIONS, EXCLUDING COAL FOR HIGH Btu GASIFICATION

Sector	Scenario 1		Scenario 3	
	10^{12} Btu	Percent of Total	10^{12} Btu	Percent of Total
Residential/Commercial				
Low sulfur coal	0		0	
High sulfur coal	0		0	
Industrial				
Low sulfur coal	5,300		3,323	
High sulfur coal, w/o control	0		2,977	
Totals, R/C plus Industrial				
Low sulfur coal	5,300		2,323	
High sulfur coal	0		2,977	13.0
Electrical				
Fluidized-bed combustion	3,000	13.1	3,000	13.1
Low Btu	3,820	16.7	3,820	16.7
Liquefaction	2,500	11.0	2,500	11.0
Stack gas cleaning	4,500	19.7	1,523	6.7
Low sulfur coal	3,700		6,677	
High sulfur coal, w/o control	0		0	
Totals, all sectors	22,820		22,820	